EXPERIMENTAL ASSESSMENT OF WATER BASED DRILLING FLUIDS IN HIGH PRESSURE AND HIGH TEMPERATURE CONDITIONS

A Thesis

by

ASHWIN RAVI

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2011

Major Subject: Petroleum Engineering

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Approved by:

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	Jerome Schubert
Committee Members,	Yufeng Sun
Head of Department,	Stephen A. Holditch

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ABSTRACT

Experimental Assessment of Water Based Drilling Fluids in High Pressure and High Temperature Conditions. (August 2011)

Ashwin Ravi, B.E, College of Engineering,Guindy

Co–Chairs of Advisory Committee: Dr. F.E. Beck
Dr. Jerome Schubert

Proper selection of drilling fluids plays a major role in determining the efficient completion of any drilling operation. With the increasing number of ultra-deep offshore wells being drilled and ever stringent environmental and safety regulations coming into effect, it becomes necessary to examine and understand the behavior of water based drilling fluids – which are cheaper and less polluting than their oil based counterpart – under extreme temperature and pressure conditions.

In most of the existing literature, the testing procedure is simple – increase the temperature of the fluid in steps and record rheological properties at each step. A major drawback of this testing procedure is that it does not represent the continuous temperature change that occurs in a drilling fluid as it is circulated through the well bore. To have a better understanding of fluid behavior under such temperature variation, a continuous test procedure was devised in which the temperature of the drilling fluid was continuously increased to a pre-determined maximum value while monitoring one rheological parameter. The results of such tests may then be used to plan fluid treatment schedules. The experiments were conducted on a Chandler 7600 XHPHT viscometer and they seem to indicate specific temperature ranges above which the properties of the drilling fluid deteriorate. Different fluid compositions and drilling fluids in use in the field were tested and the results are discussed in detail.

To my loving parents Krishnaswamy Ravi and Padmini

ACKNOWLEDGMENTS

An old sanskrit saying *Maata Pita Guru Deivam* (Mother, Father, Teacher and God) lists the four most important people in a man's life. I would like to begin by thanking my wonderful teacher (*guru*), Dr. F.E. Beck, for his support during the entire duration of this project. His experience in the field of drilling and drilling fluids was invaluable to the successful completion of this thesis. I have cherished each and every conversation I have had with him regarding this topic. He has been a treasure trove of knowledge and his encouragement during the critical stages of experimentation gave me tons of confidence. I am indebted to you, sir.

A huge shout of thanks to my committee members, Dr. Jerome Schubert and Dr. Yuefeng Sun. I have learned a lot from them. Special thanks to Vivek Gupta for his instruction on using the XHPHT viscometer.

My parents are the most important people in my life. I cannot express how much their emotional support has meant to me during these two years. A mere 'thank you' will never repay the debt of gratitude I owe them. I cannot list all my friends here, but the least I can acknowledge their words of comfort during the emotionally testing times I have faced.

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CHAPTER I

INTRODUCTION TO HTHP DRILLING AND ITS CHALLENGES

This chapter introduces the concept of High Temperature and High Pressure (HTHP) drilling and the problems associated with it. The focus is primarily on drilling fluid issues and what this research project aims to achieve in this domain.

1.1 Definition of a HTHP Well

A multitude of very similar definitions for a HTHP drilling project exist in the literature. According to Proehl and Sabins (2006), a typical HTHP project is one where the bottom hole static temperature (BHST) is expected to reach more than 350^oF and the bottom hole static pressure (BHSP) is in excess of 24500 PSI. Buchan (1993), provides a more conservative threshold based on the original Department of Trade Industry definition for the United Kingdom Continental Shelf (UKCS) and states that a HTHP well "is any well where the undisturbed bottom hole temperature at total depth or prospective reservoir section is greater than 300^oF and the anticipated pore pressure exceeds a hydrostatic gradient of 0.8 psi/ft. or pressure control equipment with a working pressure of greater than 10000 psi is required."

In this work, the second definition shall be assumed to hold whenever any reference to HTHP is made. Maldonado et al. (2006) breaks it up into three tiers as shown in Table 1.1.

This thesis follows the style of *SPE Drilling and Completion.*

Table 1.1 – HTHP Well Classification (Maldonado et al., 2006)

Tier	Classification	Bottom Hole Temperature Range	Max. Bottom Hole Pressure	Geographical Occurence
I	Normal	300 - 350^o F	15000 PSI	Common.
II	Extreme	350 - 400^{o}F	20000 PSI	North Sea and Gulf of Mexico.
III	Ultra	400 - 500^{o}F	$\geq$30000 PSI	Several Deep gas reservoirs on North American Land and Gulf of Mexico Shelf

It is in the third tier or "Ultra" HTHP window that this project has focussed on. It must be noted that significant technology gaps exist in the drilling of such UHPHT wells and are one of the main focus areas of the drilling industry today. Figure 1.1 provides a visual explanation of the classification by Maldonado et al. (2006).

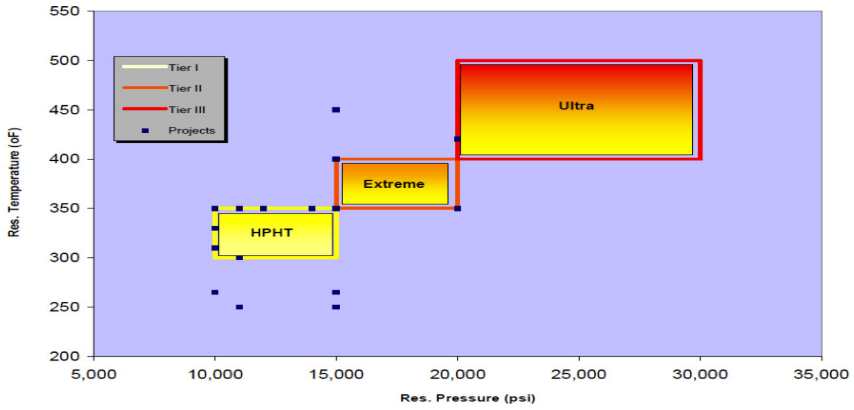


Fig. 1.1 – Graphical Classification of HTHP Wells (Maldonado et al., 2006)

1.2 The Challenges of HTHP Drilling

Operating in extreme temperature and pressure environments needs extensive planning with special attention being paid to environmental regulations. Figure 1.2 describes the sources of safety concerns in HPHT drilling published by the United Kingdom Health and Safety Executive. The fact that such drilling operations may have to be undertaken with lesser knowledge of expected conditions (pore and fracture pressures) than usual makes prior planning doubly critical (Matthews et al., 2006).

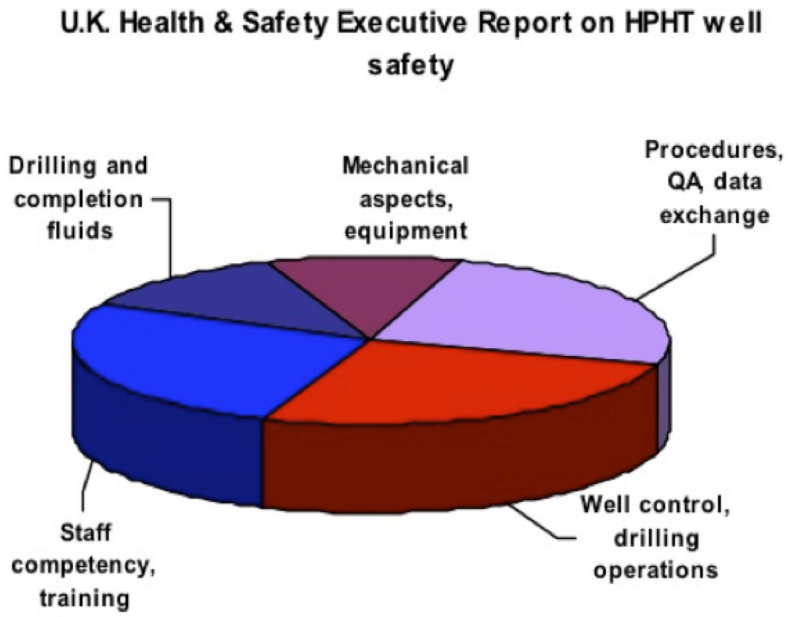


Fig. 1.2 – Safety Concerns in HTHP Drilling (Matthews et al., 2006)

The HTHP drilling problem is *multidimensional* and various factors have to be considered during the planning stage. Buchan (1993) identifies some factors related to the HTHP environment that increase the likelihood of encountering non-productive time related issues in such projects. Some of them are:

1. Heavy casing strings resulting from the considerable depth at which many HTHP wells are drilled. This necesstiates detailed torque and drag analysis to prevent drill string and casing failure. The increased temperature generally lowers material strength and this has to be accounted for.

2. Drilling and completion equipment being operated at the limits of their design. Most current LWD and MWD tools are rated to perform up to a maximum of 350^{o}F. An ultra-high temperature well will require better rated equipment to avoid unnecessary wastage of drilling time. Even if rated to work in HTHP conditions, the risk of failure increases with time of usage which significantly impacts attempts to drill for long periods of time without breaks.

3. The increased likelihood of taking a kick (defined as an unplanned influx of formation fluids into the annulus) in such conditions primarily due to very high reservoir pressures. Kick detection and remediation have to be given special attention in HTHP drilling projects. It is also very common for HTHP wells to have very narrow pore pressure / fracture pressure "windows". Thus, only a small range of mud weights can be used to drill hole sections. Drilling elongated sections at high mud weights may also lead to differential sticking issues (Seymour and MacAndrew, 1994). Figure 1.3 shows a typical pore-fracture pressure profile for a HTHP well.

4. Drilling fluid related issues resulting in loss of circulation, well control concerns and stuck pipe due to differential sticking caused by excessive overbalance.

5. Another major issue in deep wells (not necessarily HTHP) is that of low rate of penetration due to highly competent rock or poor drilling fluid selection and optimization or both.

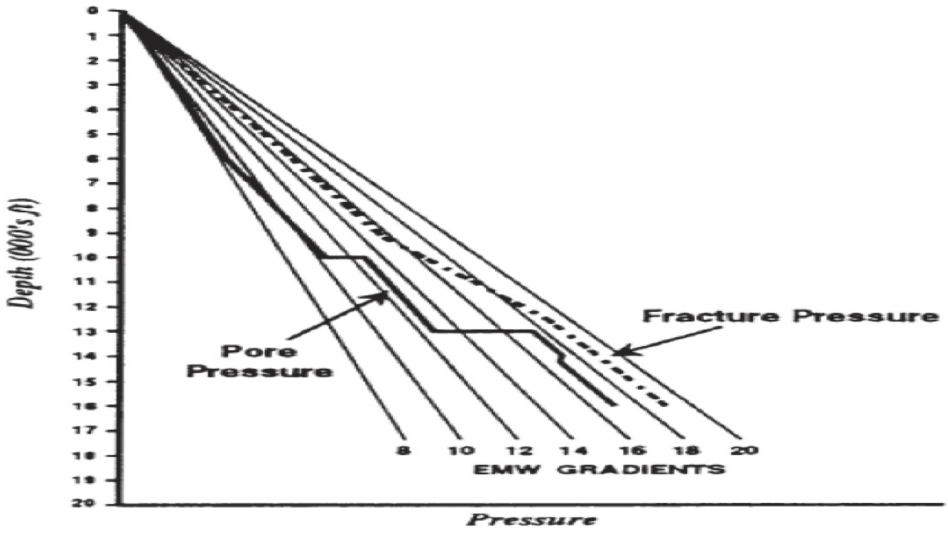


Fig. 1.3 – Typical Drilling Window for a HTHP Well (Seymour and MacAndrew, 1994)

Figure 1.4 (Rommetveit et al., 2010) provides an insight into the factors that need to be considered when embarking on a HTHP project. It is noticeable that the field of HTHP drilling optimization is abundant in problems that need to be solved and provides a rich ground for engineering improvement. The primary focus of this research project is HTHP drilling fluids related issues and their control.

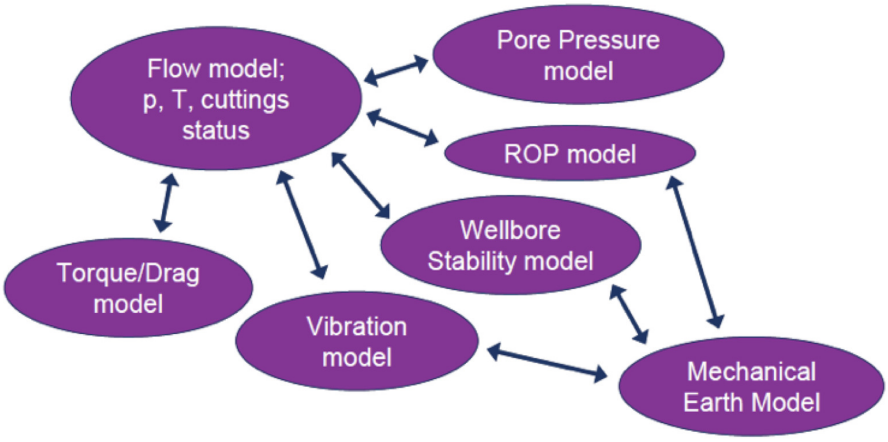


Fig. 1.4 – Factors to Consider in a HTHP Project (Rommetveit et al., 2010)

1.3 HTHP Hydraulics and Drilling Fluids

The drilling fluid is one of the major components of any drilling operation. Its importance is amplified by the severity of losses that can result from its improper selection and control. This is doubly true in HTHP operations where it is arguably the most important factor in deciding whether a project is successfully and efficiently completed. A summary of the primary functions of a drilling fluid is given below (Caenn and Chillingar, 1995) :

1. Transport of cuttings from the point of generation (the bit) to the surface and lubricating the bit.

2. Ensuring that sufficient hydrostatic pressure is exerted in the annulus to prevent an unwanted or uncontrolled influx of formation fluids.

3. Maintaining the stability of the well bore and preventing formation damage by forming a filter cake.

4. Transmitting information from the MWD tool to the surface through mud pulse telemetry.

Drilling fluids are designed to ensure that they perform these functions as efficiently as possible throughout the period for which they are used. Periodic fluid testing and treatment is carried to out to replace additives that may have been spent or to enhance certain properties (such as mud weight, viscosity or fluid loss control) as may be necessary to drill upcoming hole sections. Figure 1.5 (Bern et al., 2006) shows a subsection of the factors that are considered during fluid design and the "various interdependencies within the hydraulics and the rheology area". Hydraulics optimization is not a trivial task and needs to be viewed in a broader prospective

when it comes to HTHP wells. The following subsection discusses why this is so by considering property variations in the wellbore with pressure and temperature.

1.3.1 Property Variations in the Well Bore

In order to perform the critical functions of pressure control and cuttings removal, two properties of drilling fluids require special attention: density and viscosity (more generally referred to as rheology or rheological behavior). Controlling these properties to meet hydraulics objectives is crucial in ensuring that the well is safely drilled and completed with minimal lost time. However, it must be understood that the properties of a drilling fluid vary with respect to time and position in the hydraulics circuit. Temperatures and pressures change as a fluid is circulated in and out of the wellbore. With these changes in conditions the rheology and the density of the fluid undergoes (sometimes dramatic) change. In a HTHP well the magnitude of the change in temperature and pressure as the fluid travels from the surface to the bit can be of a very high order and it becomes important to understand how this change can affect fluid properties.

The hydraulics planning and fluid design process is very dependent on establishing how pressure and temperature conditions in the wellbore affect fluid rheology. Any calculation that ignores these effects is bound to give erroneous results and course correction along with its associated costs may be required during later stages of drilling. Any drilling fluid must be designed with the primary objective of maintaining its design properties through out the wellbore. The drilling fluid rheology not only decides the ability of the fluid to carry cuttings but also the magnitude of the frictional pressure drop that occurs as it is circulated through the system. This frictional pressure drop, apart from determining the pump pressures required to maintain circulation

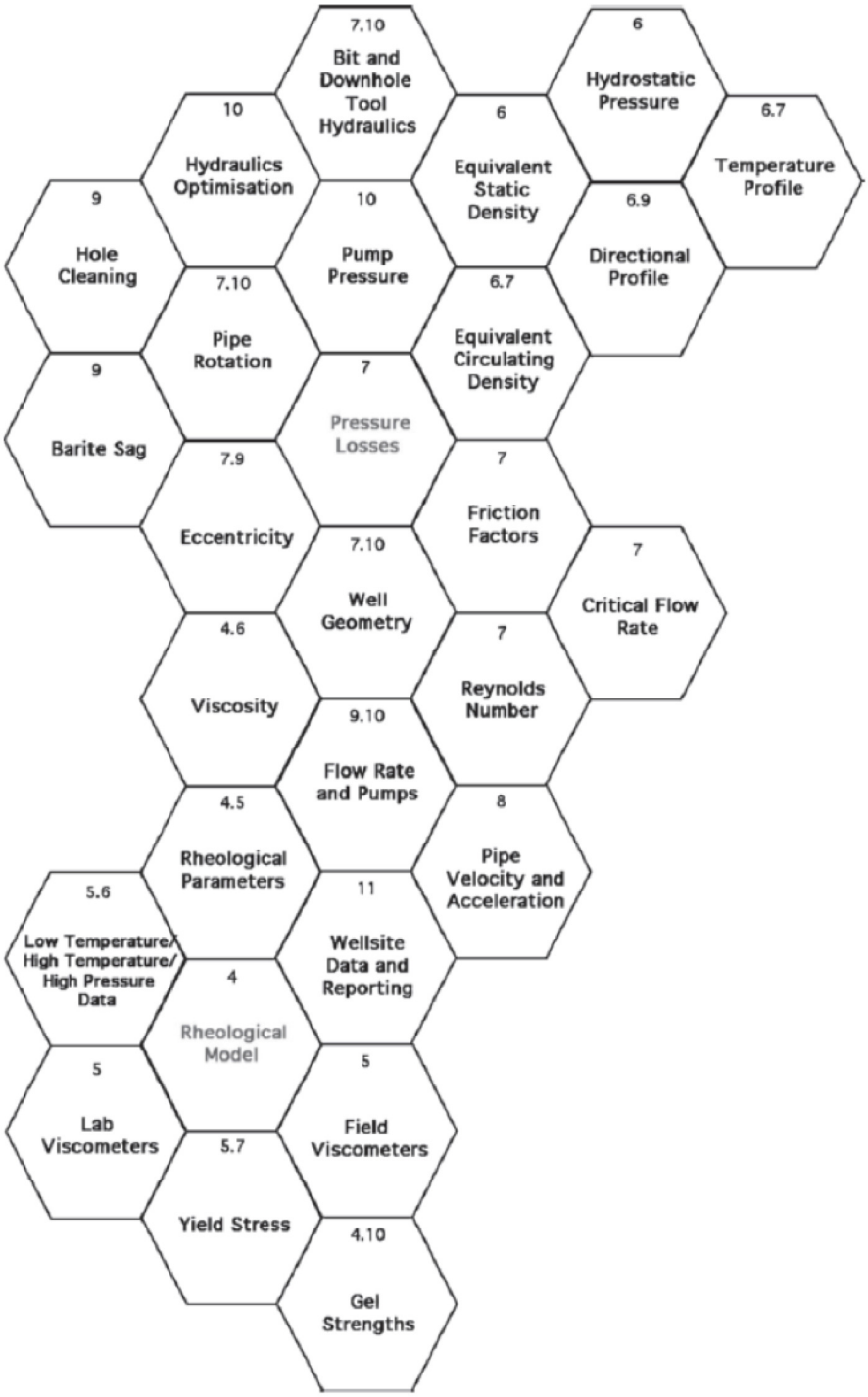


Fig. 1.5 – Drilling Fluid Design Considerations (Bern et al., 2006)

also determines the increase in pressure at the bottom of the well bore during circulation (ECD) . In drilling operations involving narrow operating windows (pore pressures and fracture pressures very close to each other, something commonly experienced in deep HTHP wells) prediction and control of ECD is a must to prevent formation fracture and lost circulation which may result in well control and wellbore stability issues. Figure 1.6 (Stiles and Trigg, 2007) shows the typical casing design for an offshore HTHP well with a TVD of 15880 ft.

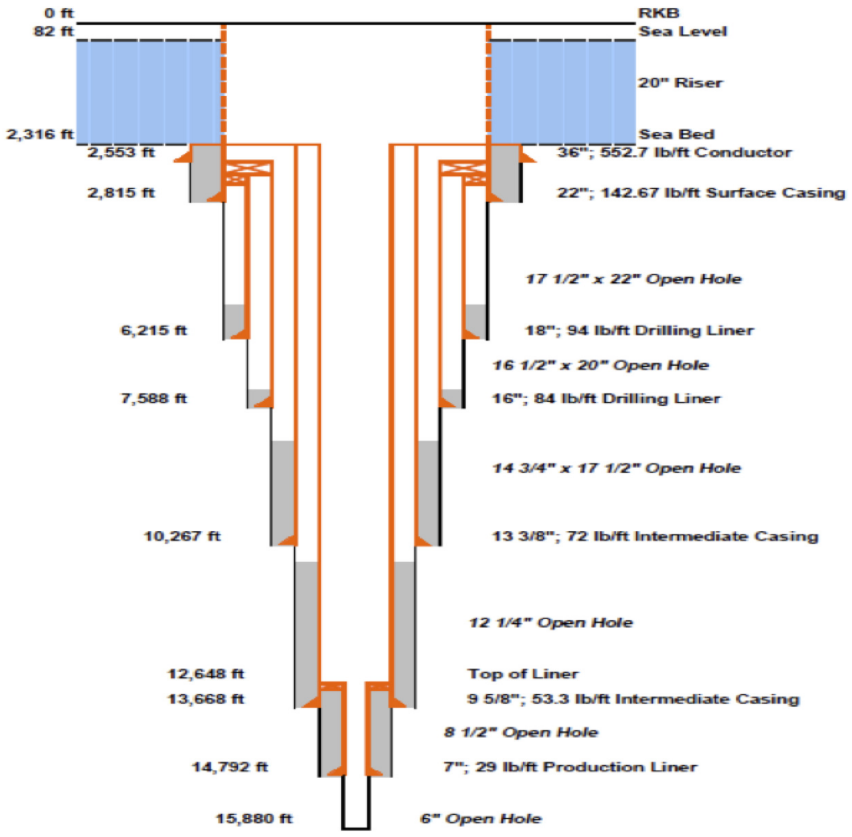


Fig. 1.6 – Typical HTHP Casing Design (Stiles and Trigg, 2007)

Figure 1.7 (Stiles and Trigg, 2007) shows the simulated and measured temperature profiles in the 6 inch hole section for this particular well. It is clearly noticeable from

Figure 1.7 that the difference between the static mud temperatures and the circulating temperatures at any depth can be quite significant and at TVD this difference is of the order of 100^{o}F. The drilling fluid should be able to perform well in the entire spectrum of temperatures that it experiences, including the low temperature regions in the riser section. Balancing the needs for high temperature and low temperature stability is a major challenge in HTHP fluids design and deployment. This balancing is achieved through a thorough understanding of fluid properties and testing.

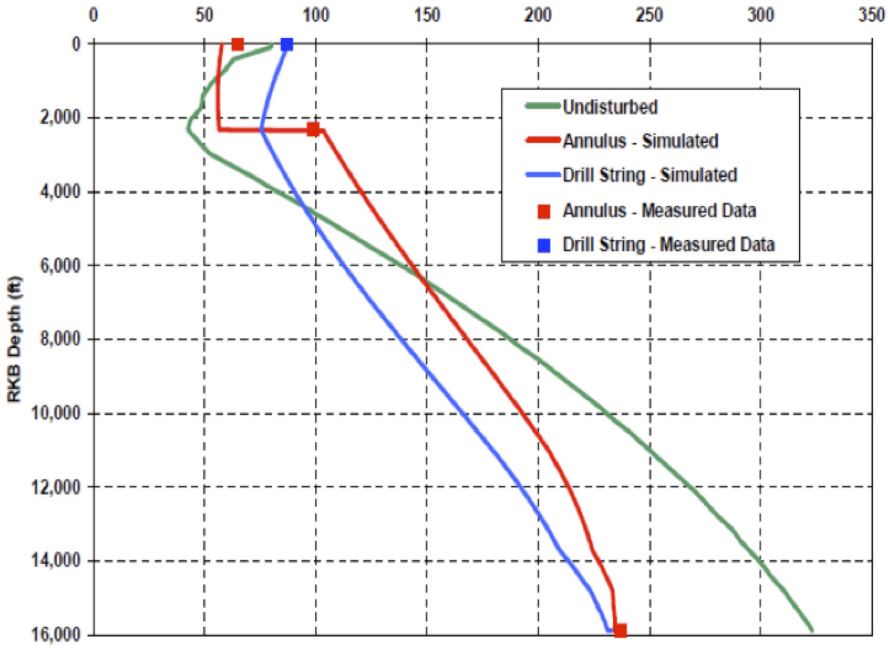


Fig. 1.7 – Temperature Profiles in a Typical HTHP Well (Stiles and Trigg, 2007)

Figure 1.8 (Demirdal et al., 2007) shows the effect of pressure on the density of drilling fluids at different temperatures. It is clear that the effects are far from negligible and must be taken into account in simulation models for HPHT drilling. Among the different drilling fluid formulations presented it is noticeable that oil based muds show more sensitivity to pressure changes than other mud formulations (Water Based Muds

and Synthetic Based Muds). Increased base fluid density will also increase drilling fluid viscosity.

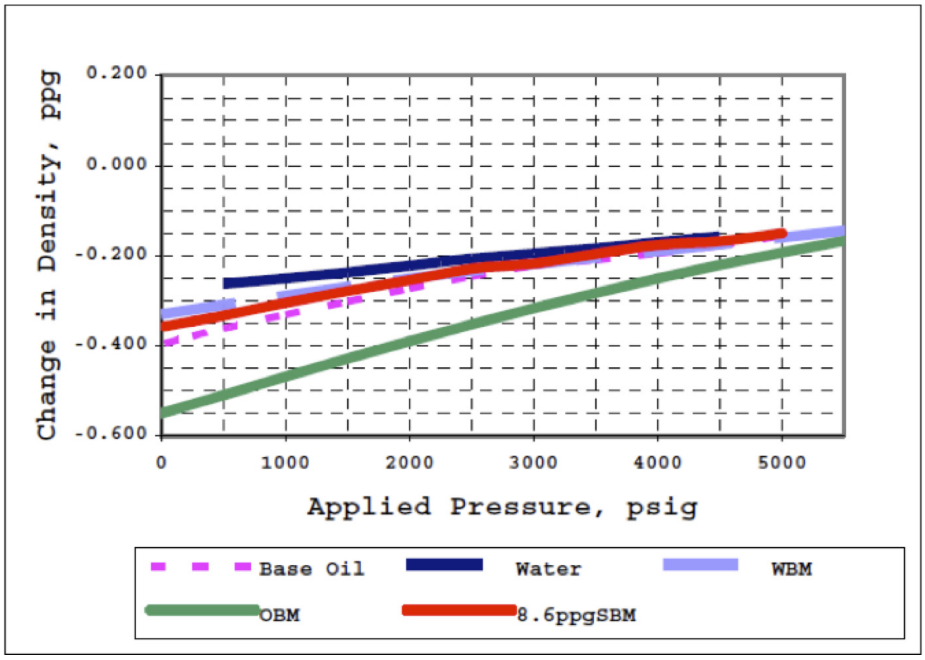


Fig. 1.8 – Effect of Pressure on the Density of Water Based Muds at 200F (Demirdal et al., 2007)

Figure 1.9 (Mullen et al., 2005) shows the combined effect of temperature and pressure on a base fluid used in a synthetic based mud (SBM). While pressure increases the density of the fluid by compressing it, temperature produces an opposite effect by decreasing the base fluid density. The combined effect of both these influences is what decides the actual bottom hole density and the equivalent static density of the mud are when the fluid circulation is stopped.

API *RP13D, Rheology and Hydraulics of Oil-well Drilling Fluids,* mentions that the effects of temperature and pressure on the density of water and water based drilling fluids are slight and may be assumed to be constant throughout the well bore. How-

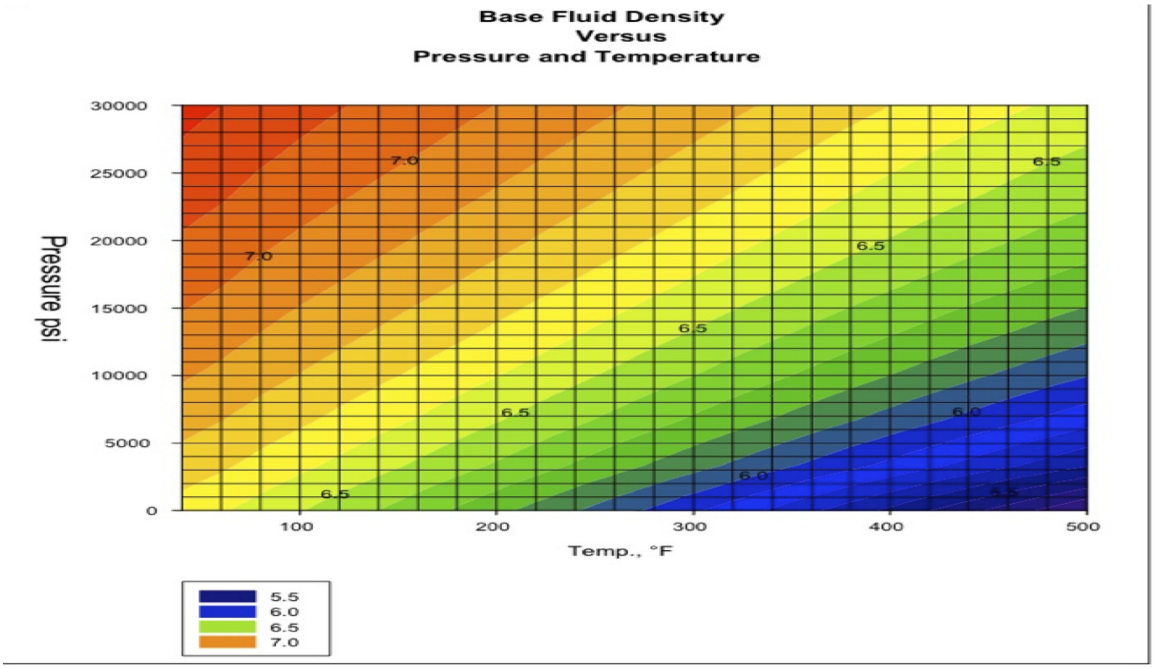


Fig. 1.9 – Combined Effect of Pressure and Temperature on an SBM (Mullen et al., 2005)

ever, considering the extreme conditions in "Tier III" Ultra HPHT wells, this assumption may not necessarily be valid.

Figure 1.10 (Zamora and Roy, 2000) shows the impact of temperature on the calculated Equivalent static densities in a 20000 ft. well. As mentioned above, even though the density variations in water based muds can be dismissed as being "slight", the combined temperature and pressure effects have the potential to throw calculations significantly off the mark. The most common bottom hole pressure formula given by,

$$BHP(psi) = 0.052 \times (TVD(ft)) \times (MW(ppg)) \tag{1.1}$$

is no longer an accurate representation of what is actually occurring and "mud weight for all mud types must forever be linked to measurement temperature".

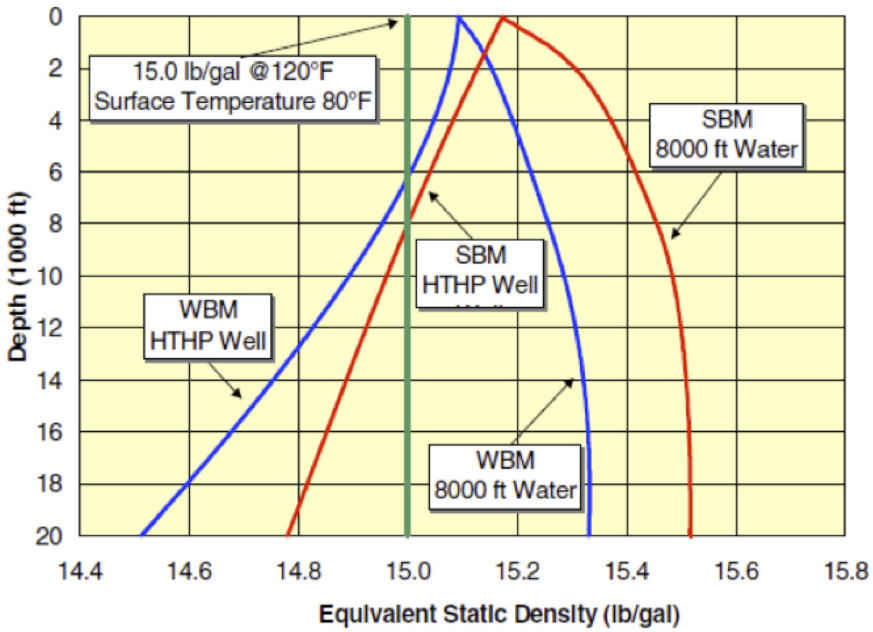


Fig. 1.10 – Effect of Temperature Variations on ESD (Zamora and Roy, 2000)

The fluid rheology is also influenced by temperature and pressure. In fact, the degree of this influence is more difficult to predict than in the case of density. Changes in the rheology of the fluid impact the equivalent circulating density during circulation and also the hole cleaning capacity. For example, a fluid that has sufficient viscosity to lift cuttings to the surface at normal conditions, but becomes too thin at down hole conditions will cause severe hole cleaning issues due to the drilled solids "dropping off" from the fluid and packing of at the bit. These problems are amplified in deviated holes where hole cleaning related problems can result in expensive and time consuming side-tracking operations or even lead to well abandonment. The need to quantify rheological changes in drilling fluids along the well bore cannot be understated. How well a drilling fluid is designed and how thoroughly it has been tested under all possible conditions it can experience is often the deciding factor in whether or not a HTHP drilling project is successful. Figure 1.11 (Zamora and Roy, 2000) shows how the yield point (a rheological property) of a WBM and SBM change

with simulated temperature in a simulated well. The degree of change in the case of WBMs is quite radical and the fluid at the bottom of the hole may not bear any rheological resemblance to what is seen at the surface. Quite obviously, the ramifications of such dramatic property variations on ECD calculations are huge. Figure 1.12 (Rommetveit and Bjørkevoll, 1997) shows how varying rheological properties impact ECD calculations.

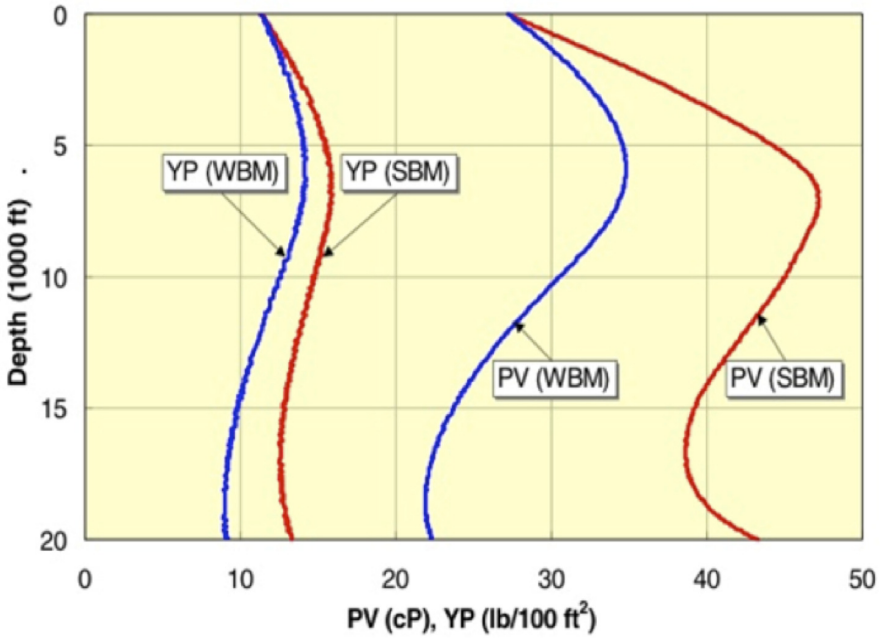


Fig. 1.11 – Variation of Yield Point in a Well Bore (Zamora and Roy, 2000)

It is worth noting from Figure 1.12 that a rheological model which assumes pressure-temperature independence is likely to produce estimates of ECD very different and often lower than those models which take property variations into account. Another point worth noting is that the ECD profile in a well changes with time because the temperature profile in the annulus is also changing from the geothermal profile at the start of circulation to a more stable temperature regime after the transient period.

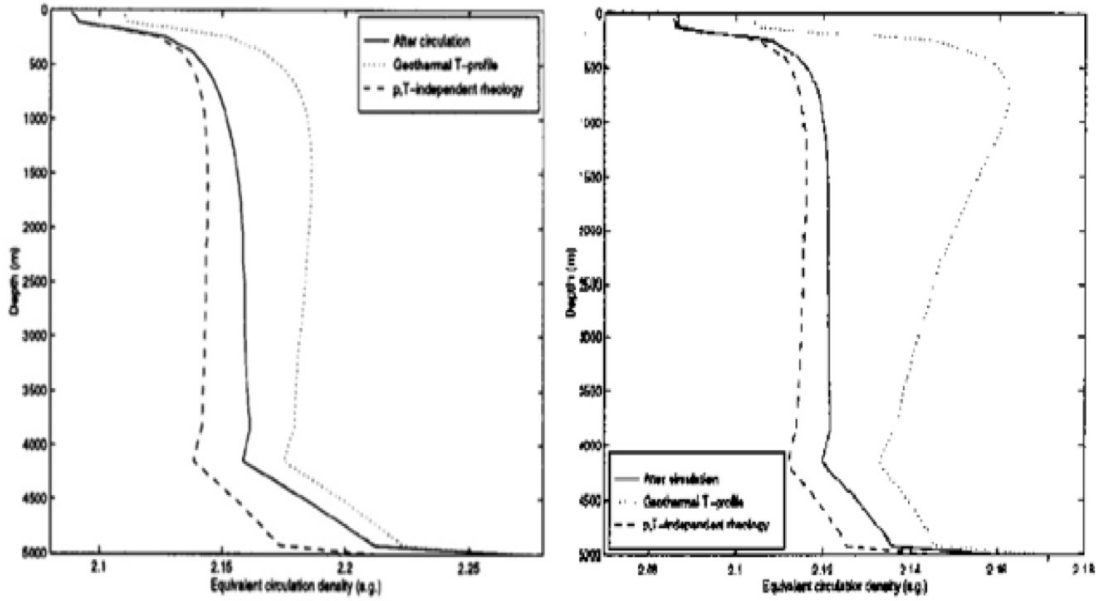


Fig. 1.12 – Impact of Varying Rheology on ECD (Rommetveit and Bjørkevoll, 1997)

Figure 1.13 (Zamora and Roy, 2000) better illustrates how ECD and ESD change with time in a wellbore.

Rommetveit and Bjørkevoll (1997) proposed a general formula for ECD calculations that takes into account the changing conditions in the wellbore given by:

$$ECD = \frac{1}{TVD}\left(\int_0^{MD} \rho(z)\,\mathrm{d}z + \frac{1}{g}\int_0^{MD} \frac{dp_f}{dz}\,\mathrm{d}z\right) \tag{1.2}$$

In conclusion, considering the numerous constraints and complications that HTHP conditions impose on hydraulics planning, a radically new approach to this process is in order. (Zamora and Roy, 2000) propose a finite difference approach, which breaks up the well bore into discrete segments with fluid properties and other relevant formation data being gathered in each segment. The calculations that ensue can be easily handled by computers in use today. This is a big step forward from the

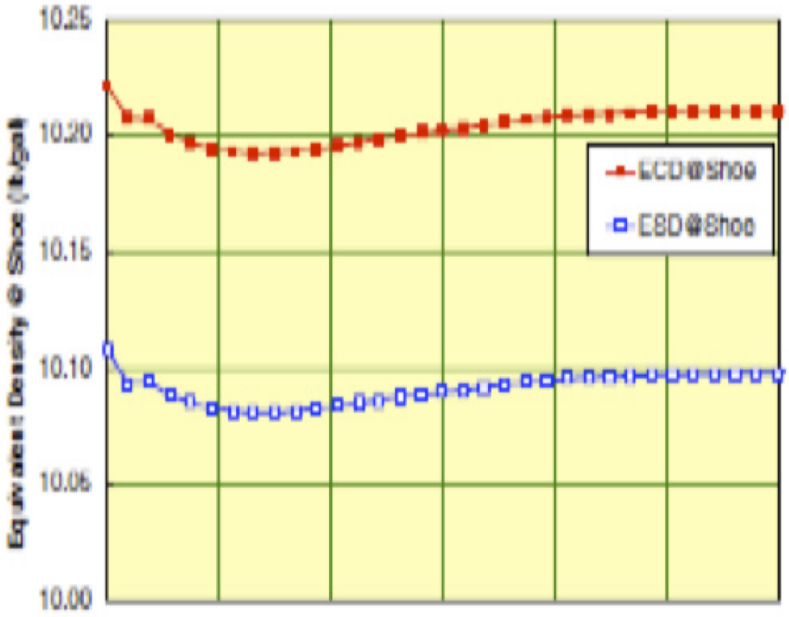


Fig. 1.13 – Variation in ECD With Time (Zamora and Roy, 2000)

now inadequate approximations and simple equations that no longer embody the complexity of the operation. Figure 1.14 (Zamora and Roy, 2000) describes this "finite difference approach".

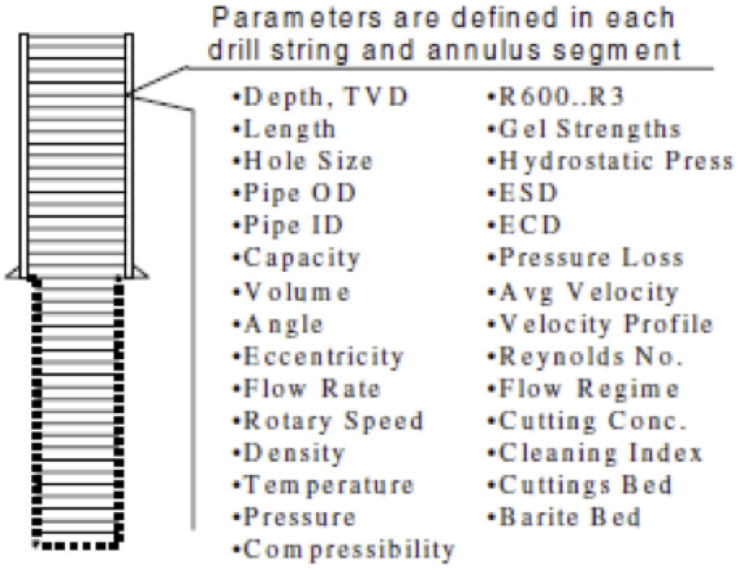


Fig. 1.14 – Finite Difference Approach to Hydraulics Calculations (Zamora and Roy, 2000)

1.4 HTHP Testing of Drilling Fluids – Why is it Indispensible?

As discussed above, gathering accurate data on the downhole behavior of drilling fluids cannot be overstated. Drilling simulators are only as good as the data they are provided with and a good deal of effort must be put into the data acquisition process. Drilling fluids are complicated in their composition and theoretical modeling of their rheological behavior under the range of conditions they are expected to endure is not only infeasible but also likely to be plagued by inaccuracies. A more pragmatic approach would be a comprehensive testing program that encompasses the entire range of temperatures and pressures. API *RP13D, Rheology and Hydraulics of Oil-well Drilling Fluids,* gives an example of one such test "matrix" based on expected bottom hole P-T conditions shown in Figure 1.15.

Temp °F	Pressure reading, psia				
	0	2000	4000	6000	8000
70	data	Data	Data	data	data
120	data	Data	Data	data	data
170	data	Data	Data	data	data
220	data	Data	Data	data	data
270	data	Data	Data	data	data

Fig. 1.15 – Sample Fluid Testing Matrix (API *RP13D*, *Rheology and Hydraulics of Oil-well Drilling Fluids*)

Extrapolation of drilling fluid behavior under downhole conditions from experimental data obtained at lower pressures and temperatures can often induce a large magnitude of errors which will ultimately lead to wrong ECD predictions. The dangers of extrapolation are evident from the Figure 1.16 (Bland et al., 2006). The "poor fit" n and k values are so different from the actual observed values that any calculation procedure that uses them as inputs will most definitely produce results that are meaningless.

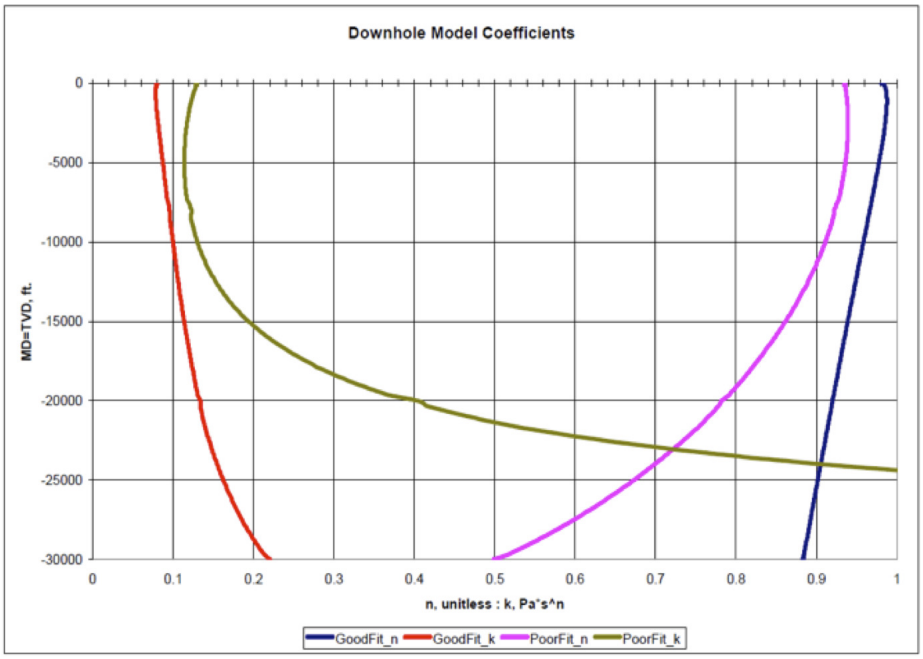


Fig. 1.16 – Errors Due to Property Extrapolation (Bland et al., 2006)

Apart from conventional rheological property testing, any testing program that claims to be complete will also have to include the following parameters as they are crucial inputs in the HTHP well planning process (Bland et al., 2006 ; Caenn and Chillingar, 1995):

1. Density (PVT behavior) at downhole conditions.
2. Static and dynamic fluid loss characteristics at elevated temperatures.
3. Chemical characteristics such as pH in downhole conditions.
4. Lubrication properties at downhole conditions.
5. Thermo physical properties of drilling fluid based on composition (required for circulating temperature profile modeling).

1.5 Types of Drilling Fluids

Drilling muds can be classified into three basic types depending upon what their "base" fluid is. They are:

1. **Water Based Muds** (WBM): Water is the base fluid and clays and other minerals are added to it to impart specific properties.

2. **Oil Based Muds** (OBM): Diesel oil or some other petroleum product is the base fluid.

3. **Synthetic Based Muds** (SBM): Synthetic oil is the base fluid, typically used in offshore wells.

Each of the above types of drilling fluids have their own advantages and disadvantages related to cost , environmental impact and reliability in extreme conditions. Synthetic based muds (SBMs) are much more expensive when compared to its water based or oil based counterparts. Oil based muds (OBMs) are generally preferred to water based alternatives in HPHT operations because of the fact that they provide good drill string lubricity, are more stable in high temperature conditions and generally do not cause clay swelling in shales. Water based drilling fluids are also prone to causing greater formation damage, hydration and disintegration of cuttings and well bore stability issues due to pore pressure elevation (Bland et al., 2002). However, despite these obvious advantages there are some drawbacks that are important and have to be considered. Bland et al. (2002) state that "despite their broad applicability, high performance and capacity for reuse, OBMs and SBMs also carry a higher unit cost and are more susceptible to lost circulation problems". Al-Saeedi et al. (2010) suggest that a significant improvement in the quality of borehole logs can also be achieved by using water based drilling fluids due to their smaller resistivity, thereby

reducing the amount of interference in resistivity logs. Figure 1.17 (Al-Saeedi et al., 2010) shows how a resistivity imaging tool provides much better resolution when used in a well drilled with a properly designed water based mud.

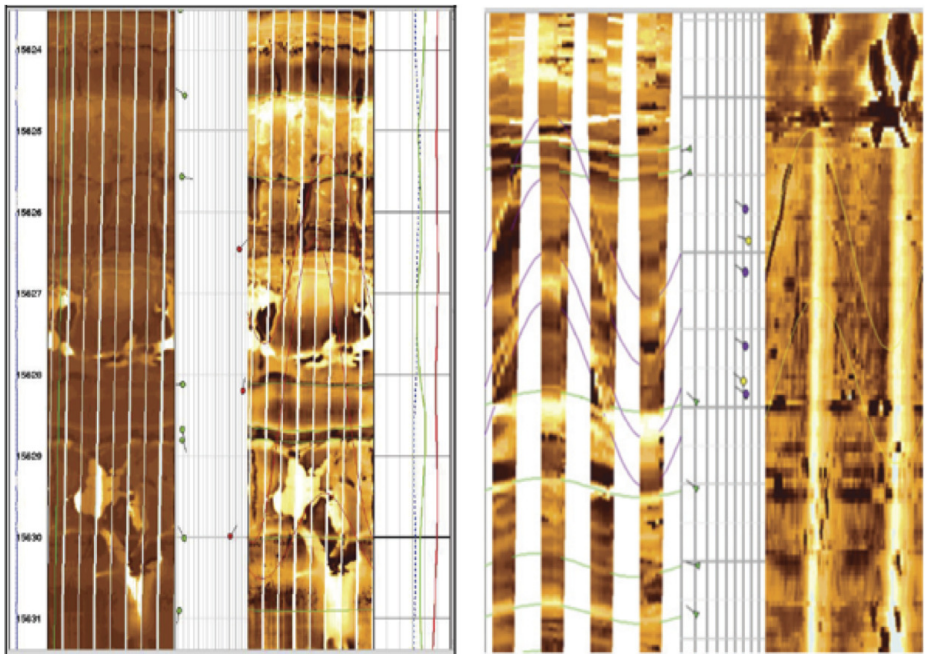


Fig. 1.17 – Effect of Base Fuid on Log Quality. The Log Obtained Using a Water Based Mud is Shown on the Right (Al-Saeedi et al., 2010)

According to Buchan (1993), early effects of gas influx can prove to be quite difficult to detect in oil based muds due to gas solubility. This could mean that the risk of an undetected kick in wells using oil based muds is greater than those using water based muds. Figure 1.18 (Bland et al., 2006) shows the solubility of methane gas in drilling fluids at various pressures at a temperature of 100^{o}F. Quite clearly, the solubility of gas in water is negligible compared to oil based alternatives. As a result of this low solubility, gas will exist as discrete bubbles in water based muds and migrate to the surface, while in oil based muds it will remain in solution till the pressure of the oil is below the bubble point pressure (Bland et al., 2006). Gas diffusion into OBMs can

also cause barite stripping leading to further well control issues. Oil based muds are also generally more difficult to dispose especially in an offshore environment and a significant amount of money can be spent in this process.

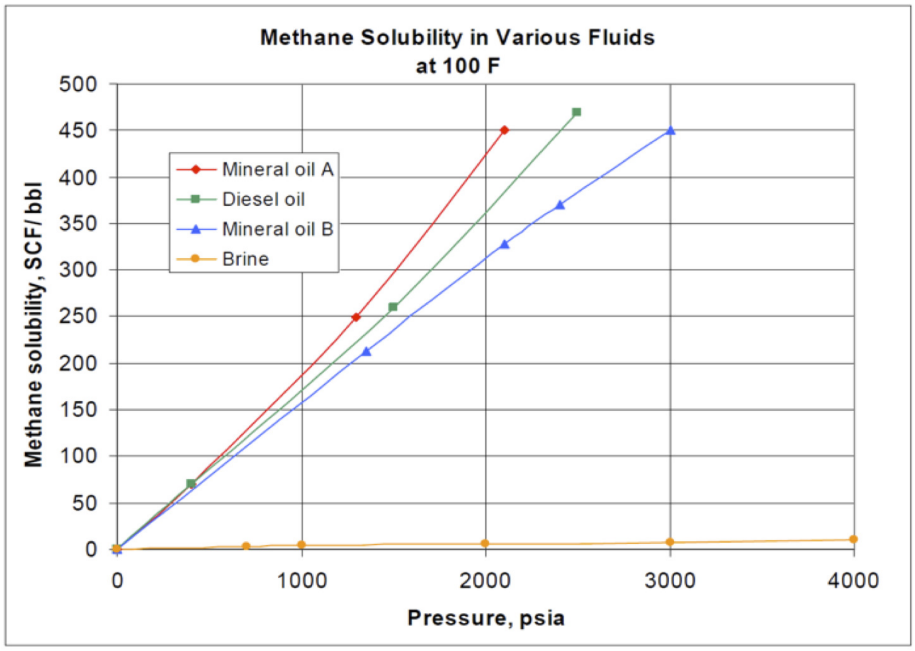


Fig. 1.18 – Methane Gas Solubility in Base Fluids (Bland et al., 2006)

The purpose of the above discussion was not to suggest that Water Based muds are the only feasible alternative and they must replace all OBMs. That is definitely not the case. But, along with the problem of gas solubility, OBMs are also becoming increasingly subject to environmental regulation. For example, in certain regions of Europe, environmental regulations explicitly prohibit the use of Oil based drilling fluids and WBMs are used to drill HPHT wells (Tehrani et al., 2009). This has led to an increased interest in water based muds. Keeping the above in mind this thesis will focus exclusively on WBMs with the focus areas being:

1. Understanding the rheological behavior of WBMs in HPHT conditions.

2. Determination of temperature based operating thresholds of WBMs through experimentation.

3. Providing general guidelines through experimental work on how these fluids must be treated to ensure better performance and prevent instability that seems to plague these fluids at extreme temperatures.

The objective of this section was to justify limiting the scope of investigation to only water based drilling fluids in this thesis. It is believed that a thorough understanding of how these muds fail at high temperature conditions will lead to their judicious application in HTHP oilfields. Armed with a sufficient amount of data through experiments, problems due to chemical instability can be more easily predicted and the fluids modified or treated in a proactive manner. Knowing what to expect and when to expect it is a powerful hydraulics planning tool.

Having described the problems associated with HTHP fluid design and testing and the reason for the emphasis on water based drilling fluids. The next chapter will focus on the existing research on the HTHP properties of water based muds through an extensive literary survey.

CHAPTER II

LITERATURE SURVEY

Having given a fairly detailed overview of HPHT drilling issues, the present chapter will focus solely on water based drilling fluids by reviewing some of the existing work that has been presented in the literature. Firstly, the different types of additives for WBMs and their respective functions will be discussed briefly. This will be followed by a survey of experimental and theoretical work done by a few authors on the HPHT behavior of WBMs and the final part of this chapter will focus on the issue of high temperature thickening or "flocculation" of WBMs having clay based viscosifiers.

2.1 Additives for Water Based Drilling Fluids

Given the many functions that a drilling fluid has to perform, it is understandable that its composition is also quite complex. Each additive has a specific function to perform and the interaction between different fluid components makes studying the high temperature behavior a challenging task. It should be noted that a detailed discussion on additives in beyond the scope of this work and only a brief overview will be presented here. The number of additives that are available and their diverse functions make the process of listing and describing them very difficult and will thus not be attempted. Table 2.1 shows some of the additives based on the function they are expected to perform (Van Dyke, 2000).

Before considering the various additives and their functions, we must first look at the three phases that make up a drilling fluid (Van Dyke, 2000). They are:

1. **Continuous phase**: This is the base fluid, which makes up the bulk of the drilling fluid volume.

2. **Non-reactive phase**: They are chemically inert solids such as drilled solids, weighting materials and some lost circulation materials.

3. **Reactive phase**: These are those additives and components that are capable of chemically reacting with the base fluid and with each other. Typical examples are clays, polymers, and deflocculants.etc.

Table 2.1 – Common Additives for Water Based Muds (Van Dyke, 2000)

Viscosifiers	Bentonite, Attapulgite, Polymers
Swelling Inhibitors	Salt, Encapsulating Agent, Lime, Gypsum
Viscosity Reducers	Lignosulfonate, Lignites , Tannates, Phosphates
Emulsifiers	Lignites, Lignosulfonate, Detergents
Fluid-loss Additives	Starches, CMC, Synthetic Polymers, Lignites, Lignosulfonate
Lost-circulation materials	Granulars, Fibers, Flakes, Slurries
Weighting Agents	Barite, Hematite, Galena, Calcium Carbonate, Dissolved Salts
Special Additives	Flocculants, Corrosion Controller, Defoamer, pH Controller, Mud Lubricant, Antodifferential sticking material

2.1.1 Additives for Viscosity

Drilling fluids need to have sufficient viscosity to lift cuttings to the surface at manageable flow rates. Water by itself has insufficient rheological properties to be able to transmit shear and perform hole cleaning satisfactorily. Thus, the viscosity of the mud has to be increased by adding suitable viscosifying agents. An important point to note is that high viscosity does not necessarily need to be conducive to the drilling process. If the drilling fluid is too viscous, the swab and surge pressures during tripping in and out may increase causing unplanned influxes (kicks) or lost circulation respectively. Highly viscous fluids also cause increased ECD, which may exacerbate lost circulation issues.

Clays are the most commonly used viscosifiers with water based drilling fluids. Clay minerals are broadly classified as (Luckham and Rossi, 1999):

1. Illites (show no water absorption)
2. Chlorites
3. Smectites
4. Kaolinites (show no water absorption)
5. Attapulgites. (Rheological properties of suspensions in water are dependent on mechanical interaction of the individual particles of clay)

The focus here will be on the family of clays known as “smectites” or to be more specific, on a member of the smectite family known as Montmorillonite. Bentonite is the most common clay based viscosifier used in the drilling industry. Chemically it is known as Sodium Aluminosilicate (Montmorillonite) (Moore, 1986).

The colloidal chemistry of clays has been a subject of extensive scholarly investigation. A detailed description of the structure of clay molecules and their interaction with water is bound be too complex and will not be attempted here. Instead, a few salient features of the mineralogy of clay relevant to future discussions will be presented. The following discussion, though incomplete is sufficient keeping in view the scope of this research.

The structural features of clay molecules can be summarized as follows (Luckham and Rossi, 1999):

1. It has layered structure comprising silica and alumina sheets stacked on top of each other.

2. Two dominant structural units are to be found in the atomic lattices the tetrahedral unit consisting of silica tetrahedrons joined to form a hexagonal unit and the octahedral unit consisting of two sheets of iron, magnesium or aluminum atoms along with oxygens and hydroxyl groups forming an octahedron. This structure is shown in Figure 2.1.

3. The octahedral and the tetrahedral sheet units are symmetric and similar in size allowing them to share oxygen atoms. This combination of one octahedral and two tetrahedral sheets is called a unit layer.

4. These unit layers are stacked parallel to each other in a structure known popularly as the Hoffman structure.

5. The sheets comprising the Hoffman structure are individually stable as they are held together by covalent bonds but their interaction with one another is dominated by Van der Walls forces which are weak.

6. Another layer of atoms may also be added to this unit layer , called the exchangeable layer (Rabia, 2002), consisting of loosely bound atoms and molecules. This is quite important as they give clays their physical and chemical properties that are useful and interesting.

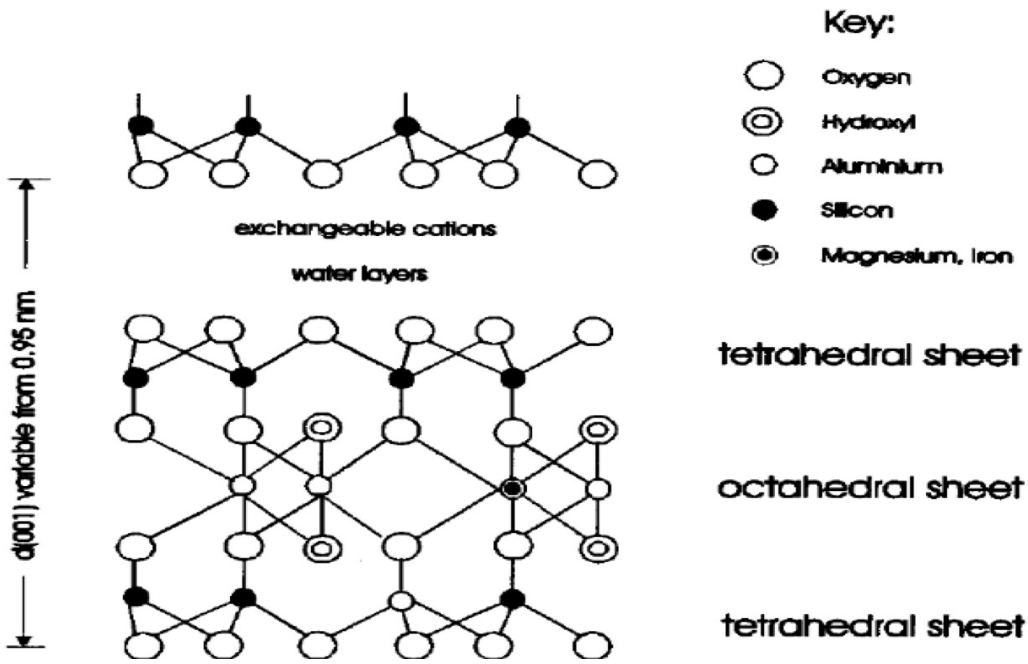


Fig. 2.1 – Structure of a Montmorillonite Clay Platelet (Luckham and Rossi, 1999)

Each unit layer of clay is around 10 Armstrongs thick. In this particular arrangement of atoms, if even one Magnesium atom substitutes an aluminium ion, an excess of negative charge will result. To account for this cations are adsorbed on the unit layer surfaces (both exterior and interior). These cations (positively charged) are exchangeable. Cation Exchange Capacity (CEC) measures the quantity of cations per unit weight of clay and is an important parameter in clay based muds. This parameter is also a measure of shale reactivity, which must be known to predict well bore stability and hole cleaning issues. In bentonite, a significant amount of these cations are sodium and hence the name Sodium Montmorillonite (Calcium may also

dominate and the name will change accordingly). Once the clay contacts water the space between the unit layers increases due to water adsorption, causing the clays to expand or "swell". This process disperses the clay particles and is responsible for the viscosifying properties of clay. The magnitude of clay swelling is dependent on whether the dominating cation is Sodium or Calcium with Sodium Montmorillonite swelling to a greater extent than its Calcium based counterpart. Figure 2.2 describes this process. Sodium Bentonite swells four times the extent of calcium Bentonite and consequently gives rise to four times the viscosity (M-I Swaco, 2002).

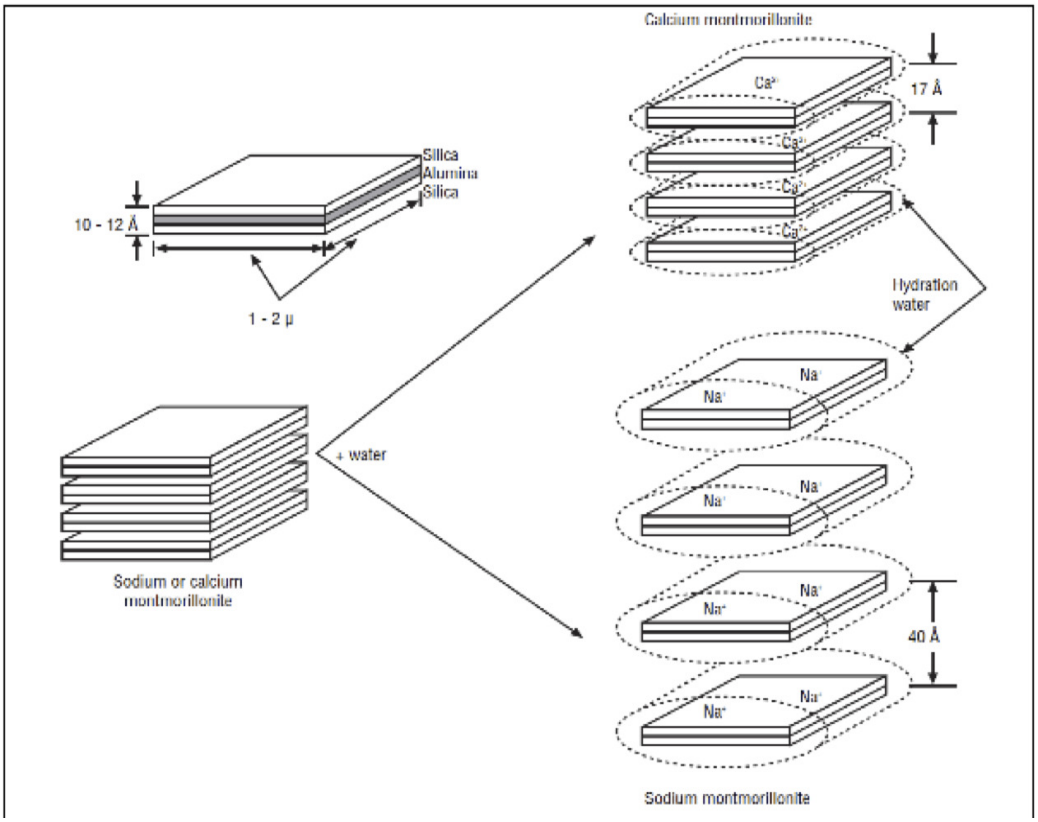


Fig. 2.2 – Hydration of Bentonite Clay (M-I Swaco, 2002)

Before proceeding to the next type of additive, it is worth considering the different types of clays that are found in formations and their impact on the drilling fluid and

the drilling process as a whole. According to M-I Swaco (2002), formation shales contain clays in the following order of abundance (decreasing):

1. Illite
2. Chlorite
3. Montmorillonite
4. Kaolinite

Since formation water is rich in Calcium, the Montmorillonite in shales is usually Calcium Montmorillonite. The previously discussed phenomena of hydration and swelling are also applicable to clays found in the formation. This causes severe bore hole stability problems during drilling (shale "sloughing") with water based drilling fluids. However, with increasing depths the clay composition is increasingly skewed towards illites which do not swell (but disperse). Shale stabilizers are added to water based muds to prevent clay swelling and associated instability problems. Figure 2.3 shows a hydrated clay sample.

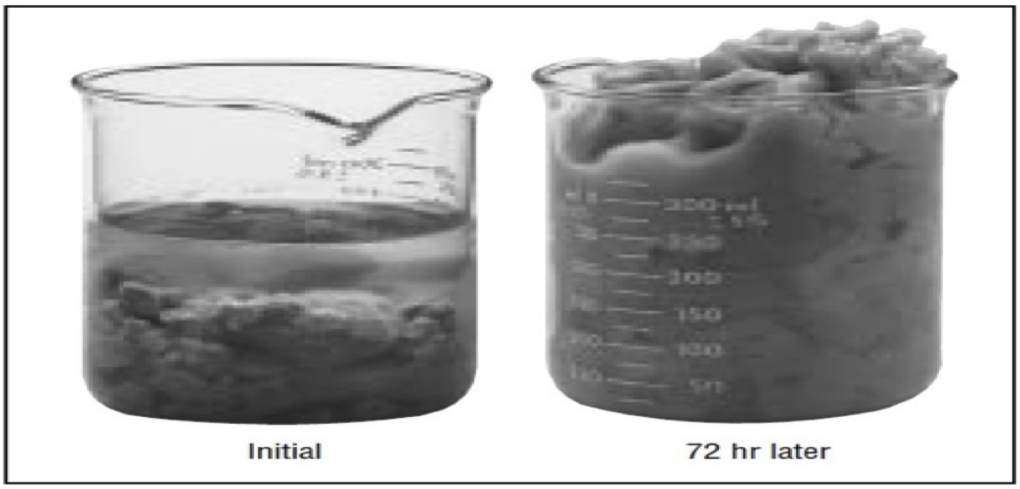


Fig. 2.3 – Hydrated Clay Sample (M-I Swaco, 2002)

Attapulgites are another family of clays that impart viscosity to water not through hydration and swelling, but by interactions among their needle like structures. They are typically useful in cases where salt water is the only available option as Bentonite will not hydrate well when the water is saline.

Polymers are also popular as additives that impart viscosity to water based drilling muds. One advantage of polymers is that they cause a negligible change to the solids content of drilling fluids. Only one polymer (Xanthan Gum) has been used in the rheological testing that will be described later. It is produced by the bacteria *Xanthomonas campestris* and is classified as a natural polymer. It is water soluble and has a molecular weight of 3 million. The structure of Xanthan is shown in the Figure 2.4.

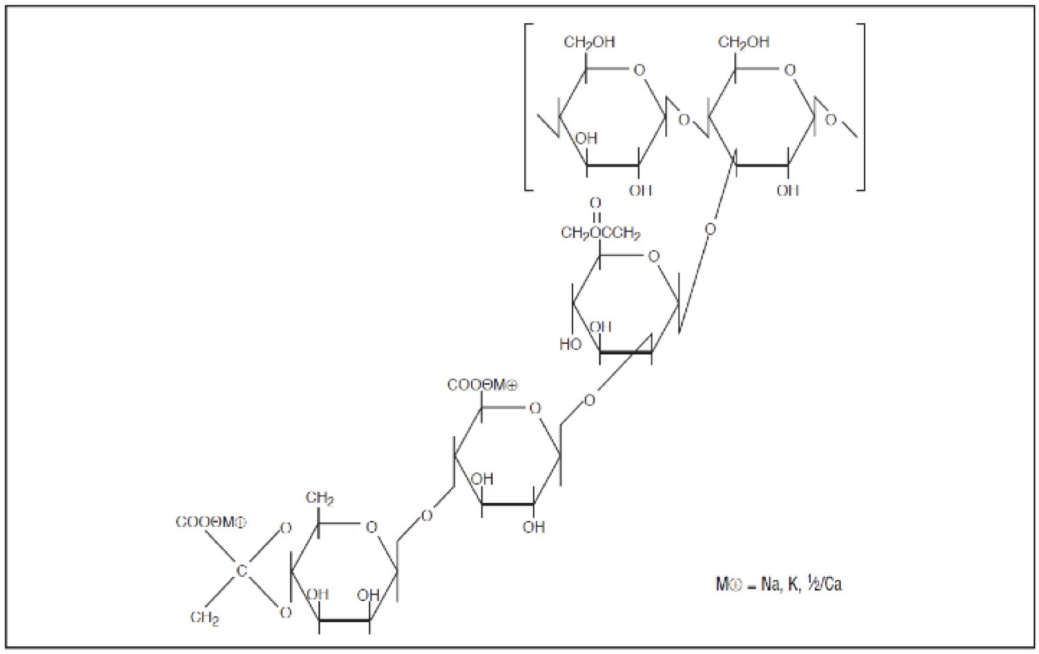


Fig. 2.4 – Structure of Xanthan (M-I Swaco, 2002)

2.1.2 Weighting Materials

Drilling fluids must exert sufficient hydrostatic pressure on the formation to prevent an influx of formation fluids. In order to perform pressure control effectively, the drilling fluids need have sufficient density. The density of the drilling muds is controlled by adding weighting materials to the base fluid. However, most weighting agents are insoluble and non-reactive. On their own, they are incapable of remaining suspended in the drilling fluid. Viscosity of the base fluid must be sufficient to ensure that the weighting materials are suspended properly. Barite sag is said to occur whenever the drilling fluid loses weighting solids due to settling and is typically caused by insufficient viscosity. Table 2.2 shows some of the common weighting agents and their chemical composition. Barite (Barium Sulphate) was used as the weighting agent in all the experiments performed as part of this research project.

Table 2.2 – Common Weighting Materials (Rabia, 2002)

Material	**Principal Component**	**Sp. Gravity**
Galena	PbS	7.4-7.7
Haematite	Fe_2O_3	4.9-5.3
Magnetite	FeO_4	5.0-5.2
Illmenite	$FeO.TiO_2$	4.5-5.1
Barite	$BaSO_4$	4.2-4.6

2.1.3 Filtration Control and Lost Circulation Material

Filtrate loss refers to the liquid phase of the drilling mud being lost to the permeable formation due to the pressure differential that exists between the drilling fluid and

the formation fluid. Loss of drilling fluid to the permeable formation typically results in a filter cake being formed on the borehole walls due to larger size particles in the drilling fluid being unable to invade the pore spaces. Ideally, the filter cake must be thin (to prevent differential sticking problems associated with thick filter cakes) and must posses low permeability to control further loss of drilling fluid (this prevents formation damage). In highly permeable formations with large pore sizes it is possible that solids in the drilling mud of adequate size may also invade the formation. In such cases, "bridging agents" are used to physically plug pore spaces near the borehole wall and prevent further formation damage. Some common bridging agents include Calcium Carbonate and ground Cellulose (M-I Swaco, 2002).

A wide range of particle sizes is preferable for good filtration control. Large particles form filter cakes of low permeability and smaller particles plug the gaps between larger particles. Bentonite, which has a large surface area, has the potential to form low permeability filter cakes. However, at high temperatures Bentonite suspensions tend to flocculate causing an increase in filter cake permeability. Deflocculaants must then be added to the drilling mud to achieve low filtration losses (M-I Swaco, 2002). Polymers can also be used as effective filter loss additives provided there are no detrimental chemical reactions with other additives. Polymers viscosify the base fluid, plug gaps in the existing filter cake and encapsulate drilled solids leading to lower filtrate volumes. Figure 2.5 shows the cross section through a filter cake.

Lost circulation refers to loss of the whole mud to the subsurface formation and this differentiates it from filtration losses. This can occur due to two reasons (Rabia, 2002). A visual explanation is provided in Figure 2.6.

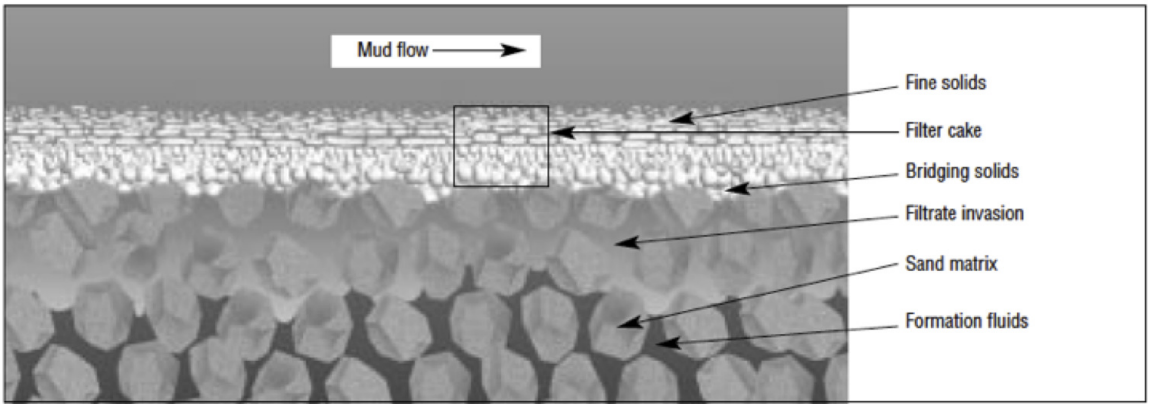


Fig. 2.5 – Cross Section of a Filter Cake (M-I Swaco, 2002)

1. **Natural Losses:** This occurs due to natural fissures and fractures in the formation caused by tectonic forces or due to large cavernous features in limestone or dolomite formations. Large cavern-like features in formations can even lead to total lost returns.

2. **Induced Losses:** They are caused by the mud pressures exceeding the formation fracture pressure leading to drilling fluid losses.

While some cases of lost returns cannot be dealt with due to the nature of the formation, there are a few ways of eliminating or reducing the magnitude of losses in other cases (Rabia, 2002). They are:

1. Reducing the ECD by reducing flow rates, proper solids control, viscosity and gel strength regulation.

2. Controlling surge pressures by reducing tripping speeds and rheological modification of the drilling fluid. There is a possibility that a thick filter cake reduces the annular clearance between the drill pipe and the formation leading to increased surge pressures, so controlling filter cake thickness may also be a viable option.

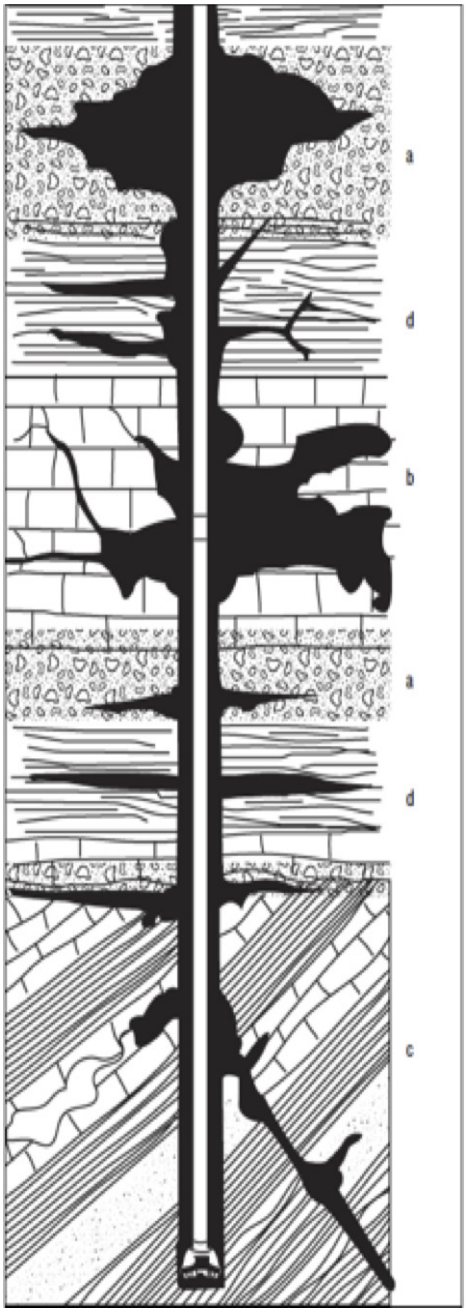


Fig. 2.6 – Avenues for Lost Circulation (a) - Unconsolidated Sands (b) - Cavernous Zones (c) - Natural Fracures (d) - Induced Fractures (M-I Swaco, 2002)

3. Setting casing at the appropriate depths using available fracture gradient information.

4. Using lost circulation material (LCM) such as mica flakes, ground nut shells or fibers to plug fissures and smaller fractures. Reinforcing plugs such as Oil/Bentonite plugs or water/Bentonite plugs may also be pumped into problematic zones but this is usually a last resort.

2.2 Existing Work on HTHP Properties of Water Based Muds

Now that the different types of additives for WBMs and their functions have been discussed, a review of the existing literature on high temperature testing of water based muds (which is the central theme of this project) will be provided. This will shed some light on the aim of the experiments that constitute the bulk of this research project and also provide a brief summary of experimental techniques currently in use.

Alderman et al. (1988) discussed the complex rheology of water based muds stated that, given the complex structure of these fluids resulting from the electrostatic interaction of clay particles, the fluid behavior is heavily determined by the shear history it has been subjected to. This is ofcourse independent of the temperature and pressure effects on rheology. The authors have sought to separate these two effects and provide a simple constitutive equation describing the change in rheological parameters with pressure and temperature. Particular attention was paid to mud preparation procedures to ensure that the clays were completely hydrated and dispersed before the actual testing procedure. Experiments were conducted using a Haake D1000/300 concentric cylinder rheometer. The authors recognized that in order to decouple rheological responses occurring due to time dependent structural changes in the drilling

fluid (which occur even after an extensive and meticulous preparation sequence) the testing procedure has to be modified to bring the fluid to what they refer to as an *isostructural* condition. This is achieved by subjecting the fluid to a "standard shear cycle history" to bring it to the equilibrium condition, thereby preventing thixotropic (transient effects resulting from structural changes independent of temperature and pressure) responses from fudging the actual data that needs to be measured. The shear rates were ramped up and down repeatedly till the hysteresis effects are negligible in between the shear rate cycles. A example equilibrium rheogram is shown in Figure 2.7 for an unweighted Bentonite mud.

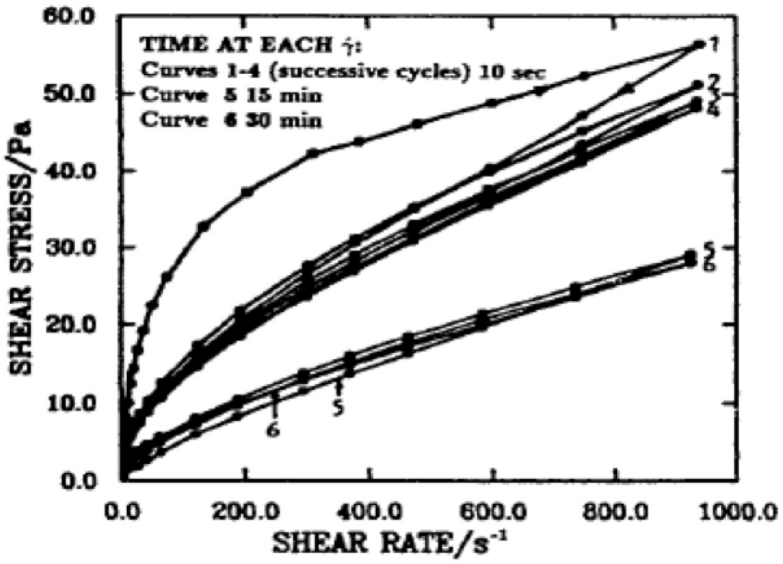


Fig. 2.7 – Equilibrium Rheogram Concept (Alderman et al. 1988)

Using the aforementioned procedure the authors tested several simple water based systems at different pressures and temperatures and observed the following (Alderman et al., 1988):

1. All fluids exhibit a yield stress followed by shear thinning behavior. The shear thinning aspect of fluid behavior is explained by a structural breakdown of the

fluid at higher shear rates.

2. The yield stress of the fluid is highly insensitive to pressure, which suggests that as far as fluid structure is concerned pressure does not produce any drastic changes. It does compress the base fluid and this may be regarded as the primary reason for rheological variation with pressure.

3. The yield stress becomes increasingly sensitive to temperature.

4. The equilibrium rheograms become less curved with increases in temperature.

The Herschel - Bulkley model was found to fit the rheological data well (refer to Appendix A for the formula describing the Herschel – Bulkley model). An example of the test results showing rheograms at various temperatures but constant pressure is shown in Figure 2.8.

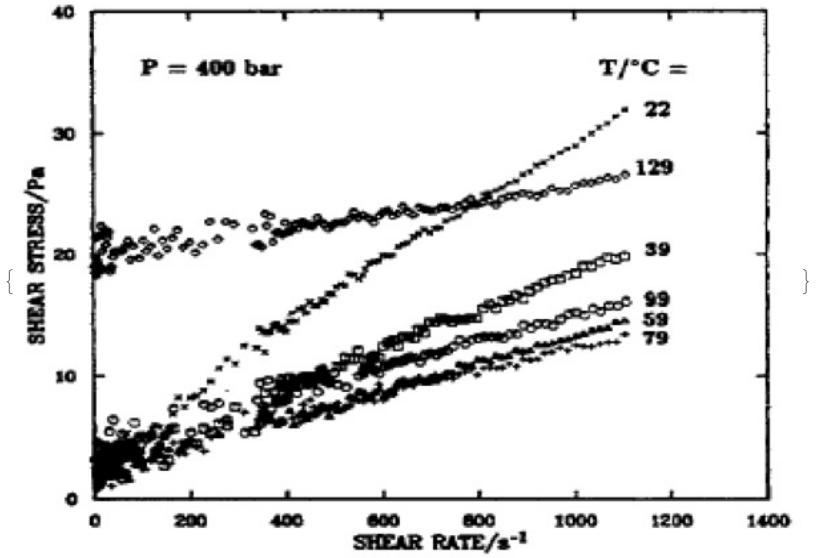


Fig. 2.8 – Effect of Pressure and Temperature on Rheology (Alderman et al., 1988)

More importantly, the authors have attempted to describe the dramatic increase in

yield stress after a specified critical temperature in a mathematical formula given by,

$$\tau_y = A_L \text{ Exp}\left[\frac{-E_L}{T}\right] \text{ if } T < T^* \tag{2.1}$$

$$\tau_y = A_H \text{ Exp}\left[\frac{-E_H}{T}\right] \text{ if } T \geq T^* \tag{2.2}$$

Carney, Guven and McGrew (1982) investigated the effect of polymer addition on drilling fluids containing clay based viscosifiers. The observations they have made on water-based muds containing Bentonite clay resonate with the central theme of the project. Since their investigation concentrated on water-based drilling fluids used in geothermal drilling operations, where the temperatures are quite extreme, it provides a rare insight into WBM behavior in Ultra HPHT conditions. The authors observed that conventional clay based systems undergo a viscosity hump after 350°F and the gelation is so intense that the fluid is quickly rendered inoperative. This gelation was seen not only in fluids containing impurities and significant solids content, but also drilling fluids with no solids content except Bentonite clay. This is significant, because there is an indication of a definite operating threshold for these fluid compositions. Figure 2.9 shows the viscosity profiles of four fluids, each of a different composition. Fluid A is a simple composition consisting of 20 PPB Wyoming Bentonite and 20 PPB southern Bentonite. Fluid D contains an additional 8 ppb of Spersene which is a high temperature deflocculant. Interestingly, despite a lower base viscosity due to addition of Spersene, the fluid does gel at higher temperatures but the gelation point is just a little higher.

Carney, Guven and Panfill (1988a) have provided some useful recommendations regarding water based fluid design for high temperature applications. Some of the most important are:

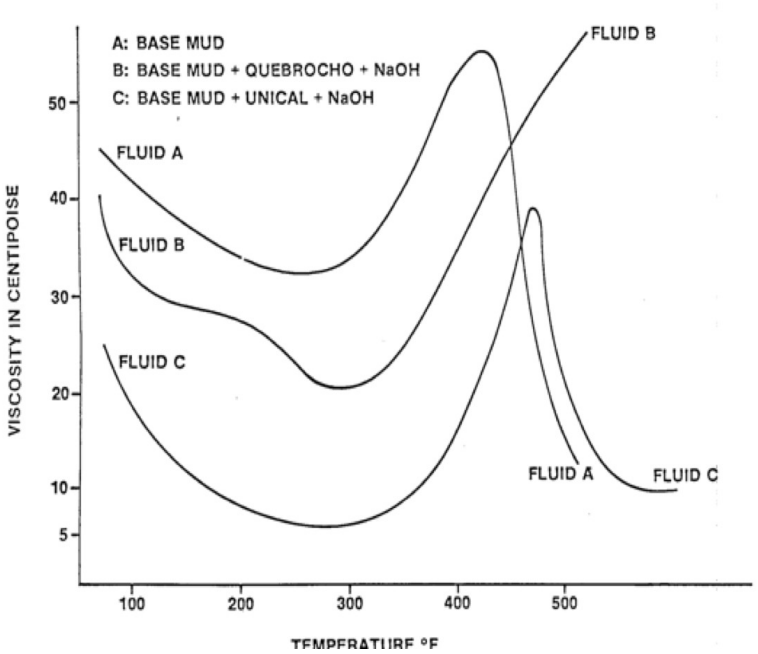


Fig. 2.9 – Bentonite Gelation at High Temperatures (Carney, Guven and McGrew,1982)

- As far as possible use a primary viscosifier other than Bentonite- this is a direct result of the poor high temperature stability of Bentonite. However, as seen in the previous section, this decision may be disadvantageous in terms of cost and to a limited extent fluid loss control as the natural sealing capacity of Bentonite suspensions may have to be replaced with special fluid loss additives. If Bentonite has to be used, keep the concentration to a minimum.

- Use polymer deflocculants to maintain high temperature rheology of water-based systems.

- Any fluid system that is designed must be ecologically acceptable.

Carney, Guven and Panfill (1988b) have also performed a comparative rheological investigation of various clays used in the drilling industry. An important conclusion is the effect of hot rolling or autoclaving on the structure and subsequently the rheo-

logical behavior of Bentonite suspensions at higher temperatures. Hot Rolling in the temperature range of 400^{o}F to 600^{o}F eliminated the viscosity enhancement that is typically seen. The authors attributed this behavior due to dissolution of smectite platelets in water during hot rolling at very high temperatures. Another important conclusion is that flocculation ultimately reduces fluid loss properties due to increased permeability of the filter cake. Figure 2.10 below shows the viscosity profile of a 6% Bentonite solution that was autoclaved at different temperatures.

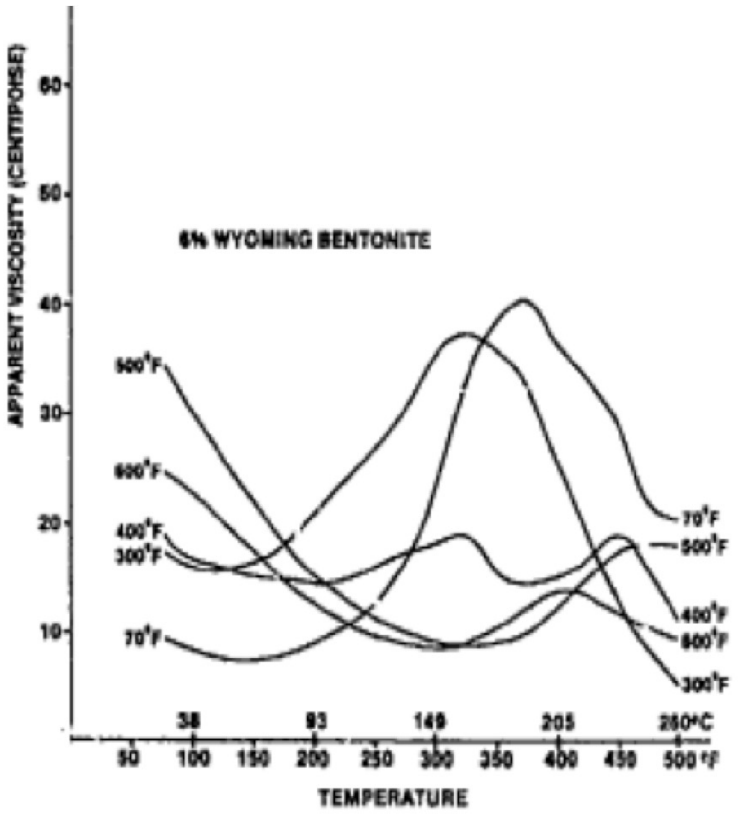


Fig. 2.10 – Effect of Hot Rolling on Bentonite Suspensions (Carney, Guven and Panfill, 1988b)

Davison et al., (1999) described the hysteresis effect in yield stress values in water-based flluids containing Bentonite. The fluid was heated to 195F(90C) and then cooled down to 30^{o}F(-1^{o}C) which is representative of offshore drilling conditions where

subzero temperatures may be experienced in the riser section. The yield stress seemed to increase during the heating cycle but does not reduce on the cooling cycle but continued to increase instead. This is a strong indicator of the fact that the mud had flocculated at higher temperatures and "this state was maintained on the cooling down cycle".

Sinha (1970) conducted rheological measurements to quantify the effect of pressure and temperature on various water based and oil based drilling fluid formulations. The author devised an interesting methodology of displaying the results of his experiments. The Figure 2.11 shows the equivalent viscosity of a 18.4 ppg water based mud used in the field as a function of depth under a simulated geothermal gradient and pressure gradient. A spike in viscosity is clearly noticeable after a certain depth that corresponds to high temperature gelation of the fluid.

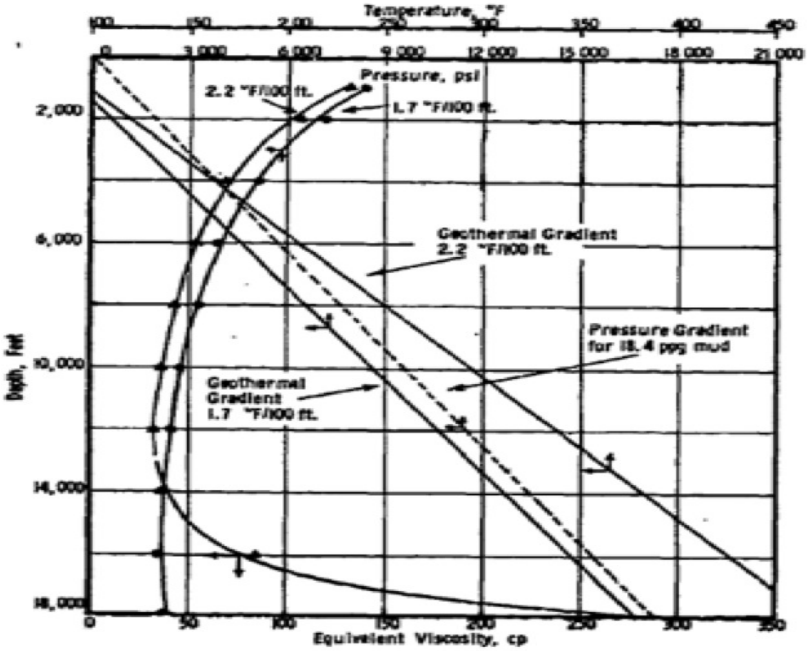


Fig. 2.11 – WBM Viscosity as a Function of Depth (Sinha, 1970)

An important aspect of drilling fluid design that seems to have been overlooked in the current literature is the fact that temperature loading of drilling fluids is cyclic in nature. In order that the drilling fluid performs well through out its period of application, it must maintain its properties equally well throughout all the heating and cooling cycles. Testing procedures thus need to be modified to accommodate the fact that gradual failure of the drilling fluid may occur over cycles as the additives that maintain fluid properties lose their effectiveness. Piber et al. (2006) recognized this and performed several cyclic loading tests on polymer and clay based water muds. They concluded that in contrast to Xanthan based fluids, which show an irreversible viscosity decrease over cycles, Bentonite suspensions have a different, more complex and stronger time and temperature dependent viscosity behavior when cyclic loads are applied. Indeed, this is evident from the Figure 2.12, where it is clearly seen that on the fourth cooling cycle, viscosity of the fluid show not only shows an abrupt increase, but the viscosity readings are also very erratic - a tell tale sign of fluid flocculation.

In the midst of all the discussion on WBM HPHT properties, the central aim of all these experimental and theoretical investigations - drilling HPHT wells at minimum cost and non-productive time – must not be forgotten. Under environmental or other constraints, when Water Based Muds have to be used to drill HPHT wells, very careful attention must be paid to several aspects of fluid design. This is important because HPHT wells are very expensive costing upto 30 million dollars (Desai et al., 2006) even without NPT. Combined with thermally induced chemical degradation accelerated by the continuous influx of contaminants this design process can be a daunting task. Careful experimentation under all possible loading conditions is the only solution to this challenging problem.

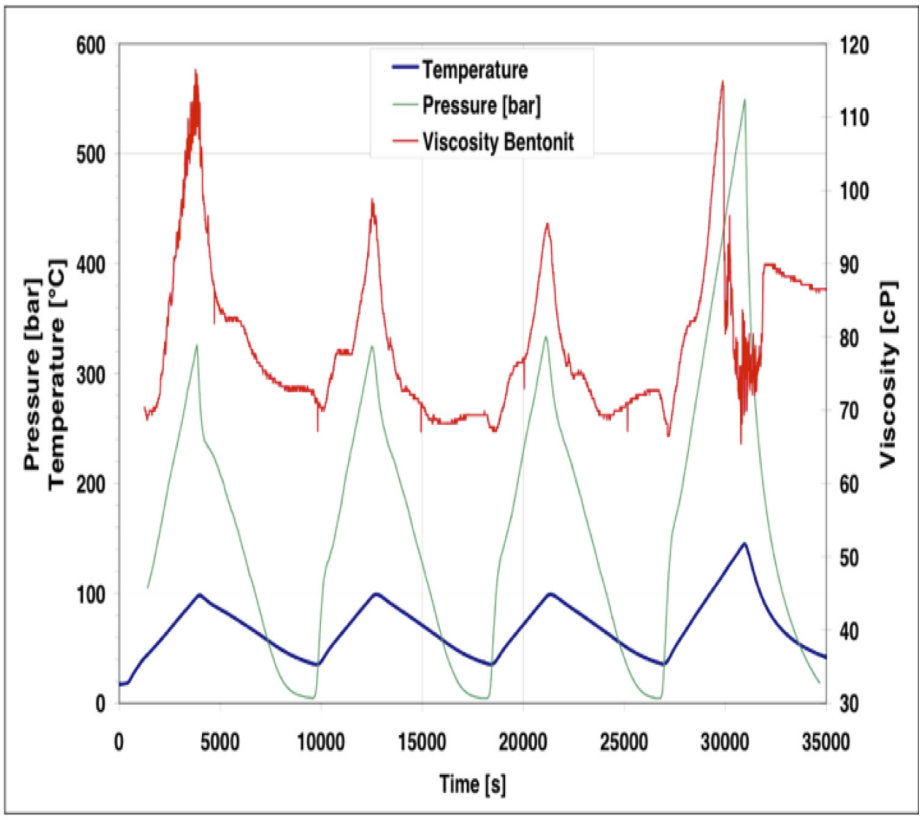


Fig. 2.12 – Cyclic Viscosity Variation of Bentonite Suspension (Piber et al., 2006)

2.3 Gelation of Bentonite Suspensions under Elevated Temperatures

The previous sections have highlighted that the often drastic change in the rheology of clay suspensions under high temperature conditions is due to a fundamental change in the nature of interaction between the clay particles in such an altered environment. Before investigating the precise nature of this change in interparticle interaction, a brief introduction to the different modes of interaction between clay particles in suspension is in order. These interactions are mostly electrostatic in nature and this can be attributed to the state of charge on the two distinct surfaces that make up each clay platelet, namely the large planar surface possessing a negative charge and the edge surface that is positively charged. M-I Swaco (2002) lists the following states

of clay particle association:

- **Aggregation** refers to face-to-face particle linking (along the large planar surfaces). This leads to the formation of large packets of clay and reduces the total number of particles in suspension. Intuitively, this leads to a decrease in viscosity.

- **Dispersion** produces the opposite effect of aggregation. Clay platelets are separated from one another, interspersed by the suspending medium (water in our case). The net number of particles in suspension increases and so dues the viscosity.

- **Flocculation** results from either edge-to-edge or edge to face association of clay platelets in what is commonly referred to as a *house of cards structure*. This causes an increase in viscosity due to the formation of interlinked flocs.

- Deflocculation is the reversal of the flocculation process leading to a reduction in viscosity. The edge-to-edge association is weakened by the action of chemicals due to decrease in the electrochemical forces holding the house of cards together. These four states of association are shown in Figure 2.13.

It is interesting to note that the edge-to-edge association model resulting in the structures shown above are not universally accepted. Luckham and Rossi (1999) suggest that edge-to-edge association can form cross linked ribbons or there could also be a band like structure as shown in the Figure 2.14 (Luckham and Rossi,1999). Regardless of the nature of association, what matters from a fluid design standpoint is that rheology is drastically modified in a manner that can be detrimental to the drilling process. The increase in viscosity that occurs when the temperature of the

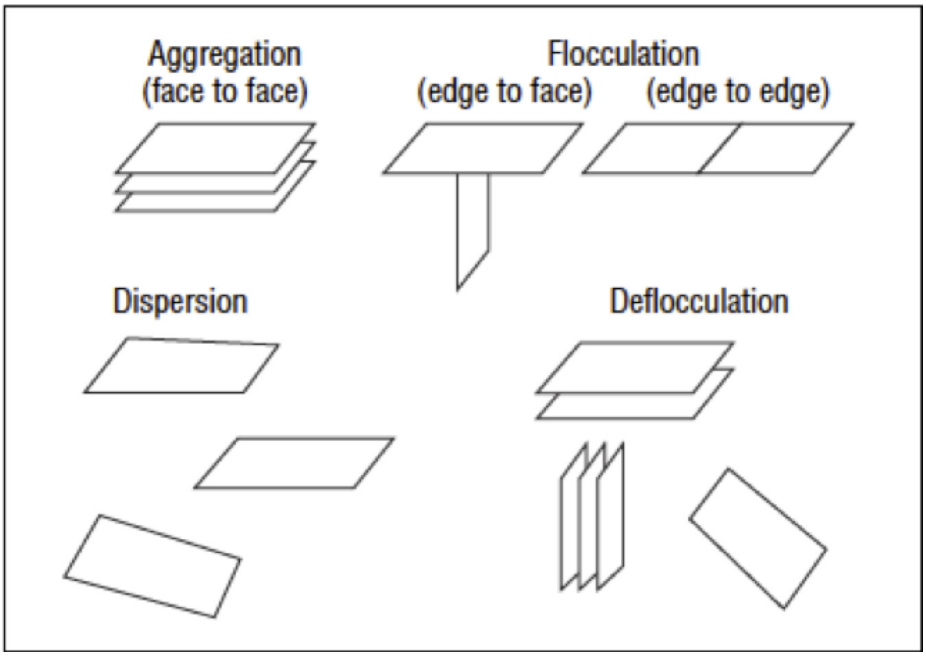


Fig. 2.13 – Types of Clay Association (M-I Swaco, 2002)

Bentonite suspensions is increased is due to a transition from the dispersed state to the flocculated state. Increased temperatures seem to induce a change in the nature of electrochemical interaction between the clay plates. Kelessides et.al, (2007) suggested that the reasons behind this pattern of high temperature behavior are not entirely known. Luckham and Rossi (1999) also determined that the origin of the flocculation behavior is not entirely clear, but suggested that this may be due to modification of the electrical double layer surrounding clay platelets by temperature.

Fig. 2.14 – Possible Flocculation Geometries (Luckham and Rossi, 1999)

The process of high temperature flocculation can be inhibited or the critical temperature at which flocculation occurs can be increased by adding deflocculating agents. Lignosulfonates are a class of compounds that achieve this purpose. According to Van Dyke (2000), the deflocculation is achieved due to lignosulfonate particles forming a coating around the clay particles, rendering the electrochemical forces that cause flocculation ineffective. This is shown graphically in the Figure 2.15. Deflocculants are not used solely in high temperature operations. Contaminants like anhydrite cement and salt may also induce clay flocculation, which can be countered with Lignosulfonate addition. Typical treatment sizes range from 0.5 to 10 PPB. Phosphates, lignins and lignites are other common deflocculating agents.

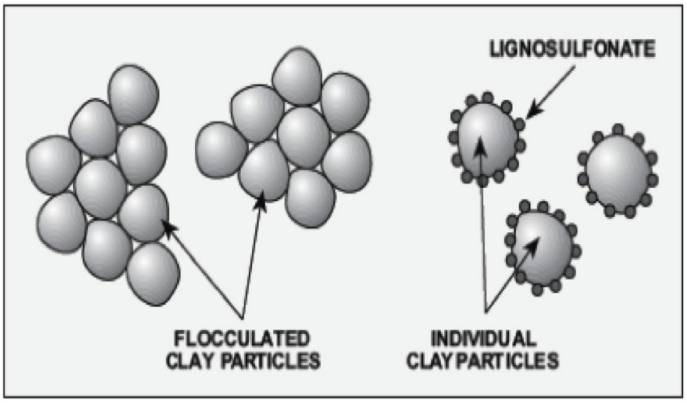


Fig. 2.15 – Action of Deflocculation Agents (Van Dyke, 2000)

This chapter has focused on specific aspects of water based mud rheology such as clay chemistry, different types of additives, high temperature flocculation and its control. These aspects will be studied in more detail through experiments in the coming chapters. The next portion of this thesis focuses on experimental equipment and methods used to study fluid rheology.

CHAPTER III

EXPERIMENTAL METHODS AND EQUIPMENT

This chapter describes the equipment used for testing the drilling fluids and its various features. Only one viscometer was used in the testing of the drilling fluids – the chandler 7600 XHPHT viscometer provided by Ametek Chandler Engineering. First, a brief overview of non-newtonian rheology measurement techniques is provided, followed by a detailed description of the equipment. The chapter concludes with a note on the mud preparation procedures that were employed.

3.1 Principles of Non-Newtonian Rheology Measurement

The viscosity of non-newtonian fluids varies with the shear rates to which they are subjected. Thus, non-newtonian rheological measurements are more complex than the rheological mesurements involving simpler newtonian fluids. For a discussion on fluid models, please refer to Appendix A. For now, it is sufficient to state that the Herschel-Bulkley model (a three parameter model) was used to evaluate the drilling fluids.

The concept behind fluid rheology measurement will not be discussed in too much detail as sufficient explaination of the topic is available in the existing literature and it is unnecessary to repeat it here. A brief overview will instead be provided. It must be understood that since the non newtonian fluid can show variable viscosity under different rhear rates (drilling fluids are mostly shear thinning), the fluid too is tested under a sample of shear rates that it is most likely to experience. In all the experi-

ments that were performed in this project, the *couette* geometry viscometer was used.

'Couette' flow refers to the flow of a fluid in between two parallel surfaces. One of these surfaces is typically moving, which causes the friction between the surface and the layer of fluid immediately next to it to move , thereby shearing the entire fluid that is present in the gap. This sheared fluid in turn exerts a force on the stationary plate which can be measured and gives an estimate of the shear stress. The shear rate of the fluid is directly related to the speed of motion of the moving plate. Figure 3.1 describes the processes occuring in a couette geometry.

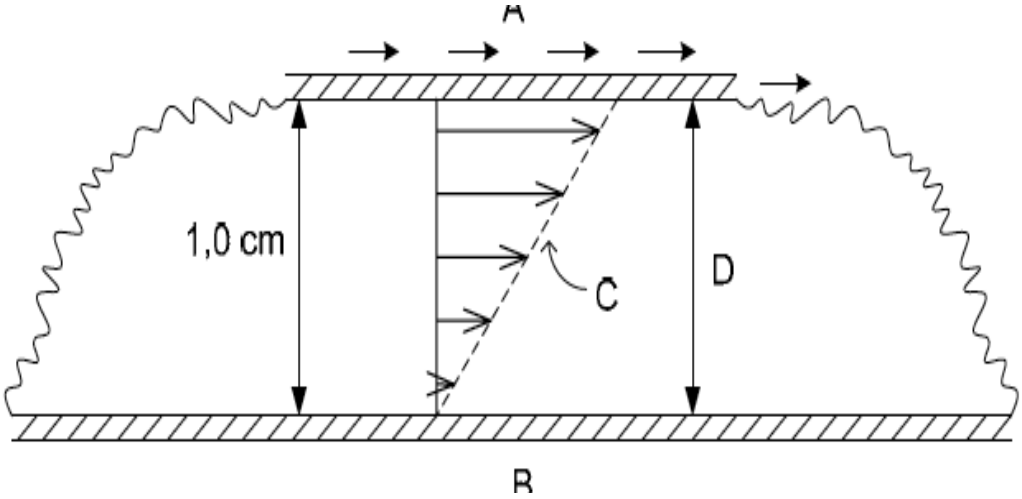


Fig. 3.1 – Schematic of Couette Geometry (Ibeh, 2007)

In practice, the couette geometry is implemented in a "bob and cup" type viscometer. In such equipment, the two parallel surfaces of the couette geometry are approximated by the surfaces of a cylindrical and concentric cup and 'bob'. The bob is usually stationary and the cup rotates. The fluid that is present in the gap between the cup and the bob is sheared. The shear stress acting on the fluid is measured in terms of torsional force exterted on a spring attached to the stationary bob. The shear rate is

a direct function of the geometry of the cup-bob system and the RPM at which the rotor is moving. The shear stress is often read off a calibrated dial attached to the torsion spring and hence the use of the term 'dial reading' in the place of shear stress is prominent. This term shall be used interchangably from here on in the thesis. A schematic diamgram of the system is shown in the Figure 3.2.

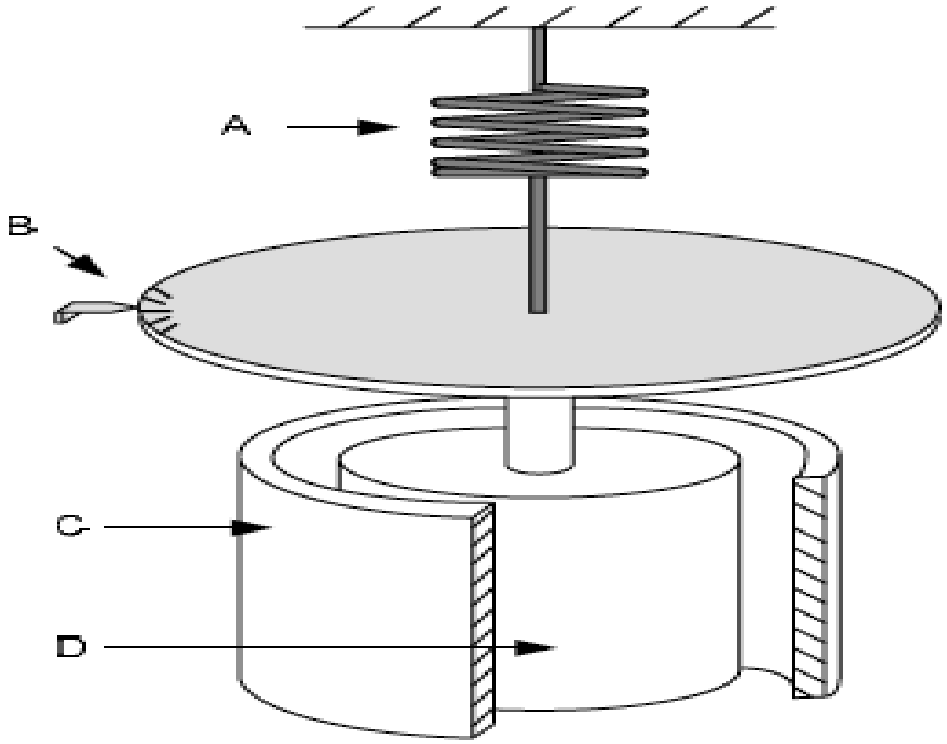


Fig. 3.2 – Bob and Cup Viscometer Geometry (Ibeh, 2007)

In the drilling process, the flow loop of the drilling fluid can be segmented into groups based on the shear rates that a drilling fluid experiences when flowing through them. There are three shear rate ranges – low, medium and high. The low shear rate regions are represented by viscosity measurements at 3 RPM and 6 RPM. The medium shear rates are encapsulated by the 100 and 200 RPM rotor speeds and the high shear

rates by the 300 and 600 RPM speeds. An oilfield viscometer will thus have atleast six preset speeds at which the rotor can be run so that the fluid properties can be mesured at each representative shear rate. Any test involving this six speed sequence (from lowest to highest) shall from here on be referred to as a 'baseline' test sequence. A FANN 35 viscometer with an attached thermocup was used to validate the room temperature baseline tests from the XHPHT viscometer.

3.2 The High Temperature - High Pressure Viscometer

Since the drilling fluids in this project are being tested in the UHPHT range it is not possible to use conventional viscometers whose range of operation (maxiumum pressures and temperatures) is scarcely enough to meet the needs of ultra high temperature testing. To overcome this obstacle a XHPHT viscometer provided by AMETEK engineering – the CHANDLER 7600 – was used. This viscometer has the capability to test fluids upto a maximum of 40000 PSIG and 600^{o}F. The machine is almost fully electronically controlled and uses the same principle of viscosity measurement as the typical oil field viscometers (couette geometry flow). A photograph of the equipment is shown in Figure 3.3.

The salient features of the equipment are:

- Viscometer meets the ISO 10414-1, 10414-2 and API RP13 requirements.
- Bench-top instrument.
- PC based data acquisition and control system.
- Automatic control of sample temperature and pressure using PID controllers.

Fig. 3.3 – The Chandler 7600 Viscometer

- High pressure (40,000 PSI/276 MPa), high temperature (600°F/316°C) sample testing.
- Mixing of sample during test using mixing screw on outside diameter of rotor.
- Automatic control of instrument, including data collection, shear rate scheduling, rheological model fits (n and K), display and calibration.
- Automatic 10 second and 10 minute gel strength measurements.
- Remote magnetic drive system, which eliminates interference with ferromagnetic suspended solids.
- Sample wetted parts made from 300 series stainless steel and other corrosion resistant high strength steel.

- Stepper motor and magnetic drive used to generate shear rates, providing high accuracy and stability.
- High resolution measurement of torque (28800:1 encoder), jewel bearings.
- Safety systems designed into the instrument and software (over-pressure, overtemperature).
- Microsoft Excel compatible data output.

One of the main features of this equipment is that there is no mechanical linkage between the servo motor that provides rotation and the rotor system. The linkage is purely magnetic. This simple design enables the fluid to be subject to very high pressures with minimal risk of leakage. Unlike conventional viscometers, the dial reading measurement system is also magnetic in nature. The defelection of the bob due to the shear stress is recorded electronically by a magnetic encoder which transmits the data in real time to an acquisition system. The motor speed can be accurately controlled and may be set to any required speed schedule. All the test parameters are input electronically and the test is automatically controlled to stay within the desired temperature and pressure range. Figure 3.4 shows a cross section of the test cell of the viscometer.

Pressures and temperatures can also be controlled electronically in accordance with a preset schedule. The pressure in the system is maintained using an air over water pressurising system. Mineral oil is used as the hydraulic fluid. Though the mineral oil does make contact with the tested fluid, it has been ensured that it does not affect rheological measurements in any way. The temperature control is through a heater

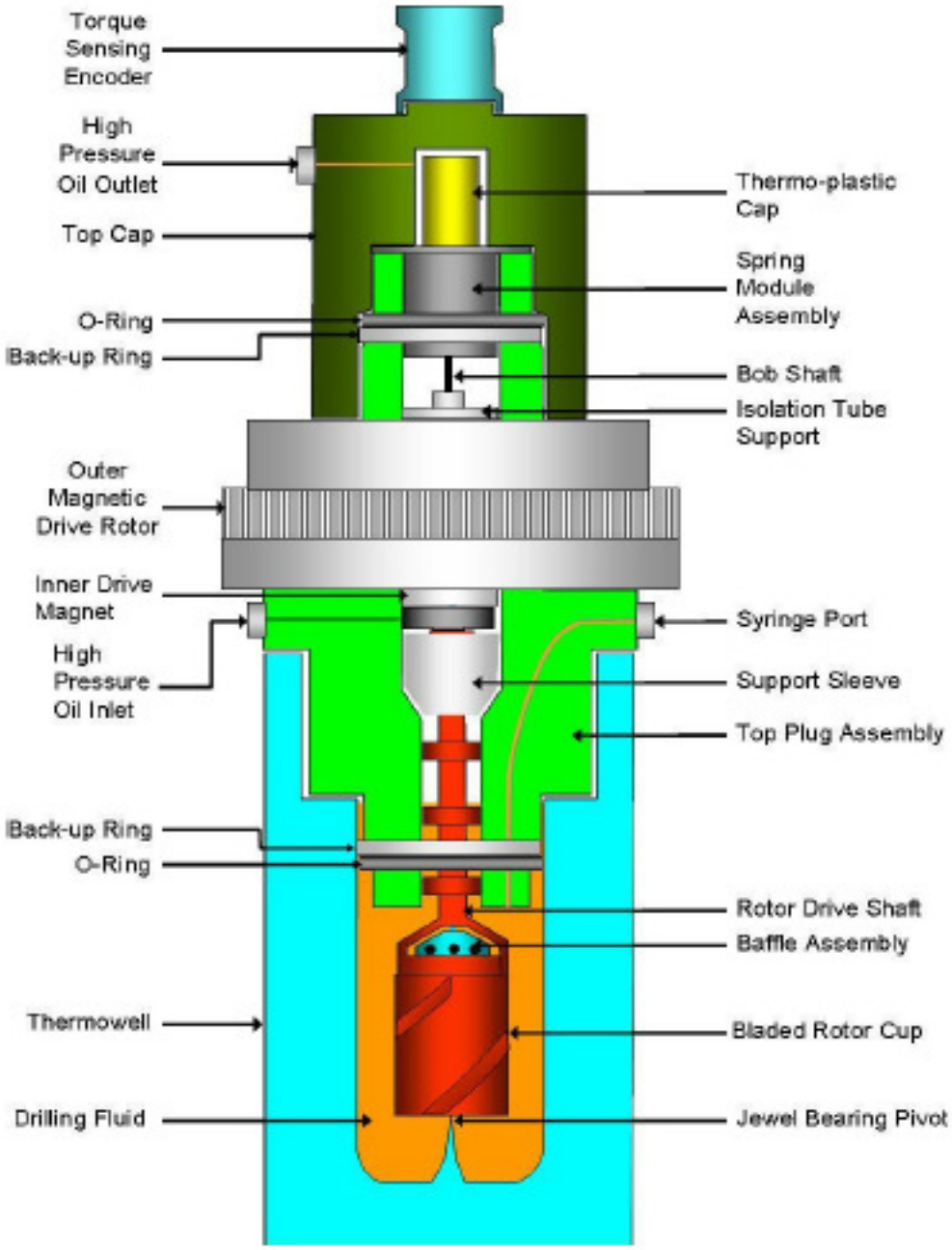


Fig. 3.4 – Viscometer Cross Section (Ibeh, 2007)

coil. The entire test cell is lowered into a thermowell before testing commences and then the heater coil is turned on. Cooling down cycles are however uncontrollable and the system is effectively air cooled. Figure 3.5 shows a typical test schedule in which the temperature and pressure are varied in steps and baseline tests are conducted at each step.

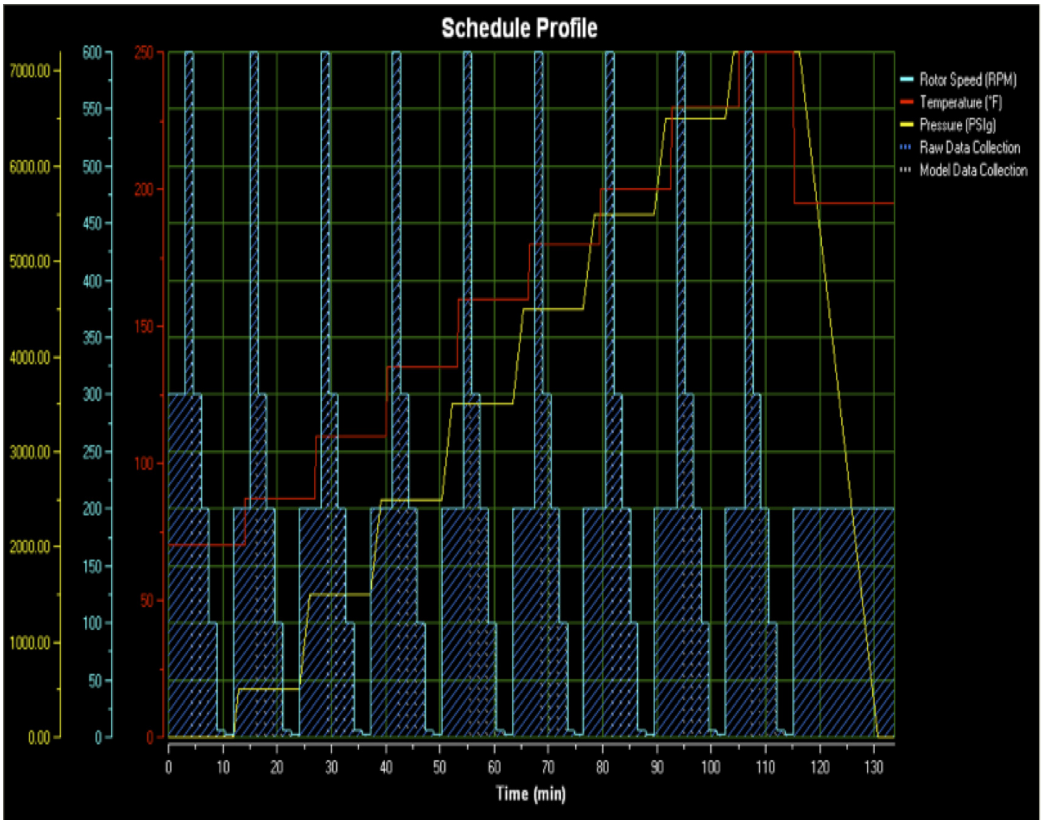


Fig. 3.5 – Schematic of Typical Test Schedule

Another extremely critical feature of the viscometer is that it provides a real time digital data display of temperature, pressure and dial reading. The rate of data acquisition can be set to as low as one data point every two seconds. This enables a close real time rheology monitoring to take place. The rate of temperature and pressure increase of the sample can also be set to any desired value. Cool down cycles are

typically less 'controllable'. Pressures can be ramped down at any desired rate, but the sample will have to cool naturally.

Since the operation of the equipment is at extremely high temperatures and pressures, several safety precautions have to be followed during operation. Care must be taken not to exceed the operating limits of the equipment. Though almost all of the processes are automated, there must be contninuous manual monitoring of the equipment parameters to ensure that there is no anomalous activity. This becomes doubly important in fluid flocculation tests, when a manual override has to be performed in case the fluid becomes too thick and begins to damage the spring assembly. Periodic calibraton of the equipment has to be carried out using a calibration fluid (200 CP silicone fluid). This is done to ensure that the equipment gives consistent results devoid of long term drift.

The first experiment of the series was conducted to determine if there was any drift in dial readings with time. Such a validation is necessary because in most of the tests involving high sample temperatures and pressures it takes quite a while for the input parameters (especially temperature) to stabilize and there may be a serious lack of accuracy if the dial readings drift with time. It must be noted that the sample is always being sheared by the rotor during the transient stages of the experiment. This is necessary because of the thixotropic nature of the fluids being tested which means that the dial readings may take some time to re-stabilize when the rotor is started again.

In order to test the above mentioned drift characteristics of the viscometer, a pilot test was conducted on a bentonite-water solution. The concentration of the sample

was set at 20 pounds of Bentonite per barrel of water. The bentonite clay was pre-hydrated in water for 16 hours and then sheared in a high shear mixer for 30 minutes. The sample was then tested in the Chandler 7600 viscometer at room temperature and pressure. The following schedule was followed.

- **Step 1:** Shear at 300 RPM (510.60 1/s) for 5 minutes.
- **Step 2:** Conduct 4 baseline tests to get four sets of dial readings at 600, 300, 200, 100, 6 and 3 RPM.
- **Step 3:** Shear the sample at 300 RPM continuously for one hour.
- **Step 4:** Conduct four more baseline tests as described in step 2.

The results of the experiment are displayed in the Figure 3.6, which shows the dial readings as a function of shearing time. The baseline tests (8 in total) can be seen clearly, where there is an increase in dial readings with an increase in RPM of the rotor. Each rotor speed has a dial reading associated with it, and as the RPM is varied the dial reading curve shows as staircase profile that is evident in many of the experimental graphs that follow. The rotor speed is maintained at a specific speed for 90 or 180 seconds to allow for the dial readings to stabilize after which they are recorded as model data. This will eliminate the influence of thixotropy that is usually a feature of most drilling fluids. The 10 minute and 10 second gel strengths are also recorded for the fluid. The fluid is sheared at 300 RPM (510 1/s) for 42 seconds before the shear rate is reduced to zero for the gel strength tests. Separate commands are available in the equipment software that automatically record gel strengths when the rotor is restarted at 3 RPM.

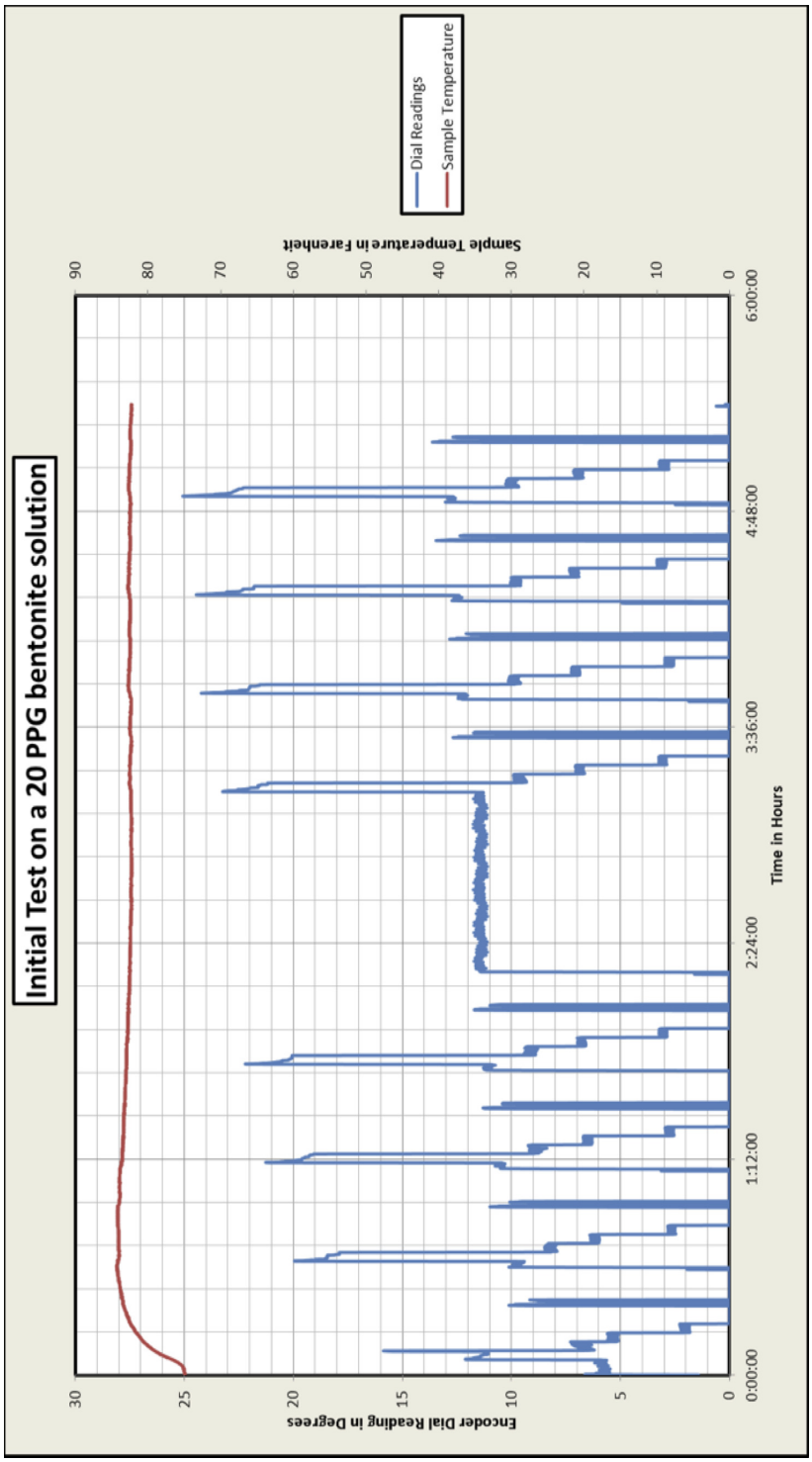


Fig. 3.6 – Pilot Test on Bentonite Suspension

As it can be seen, there is some rheological variation initially, but its magnitude reduces considerably as time wears on. During the one hour shear period too, there is very little variation in dial readings observed (some oscillation about a mean value exists, but its magnitude is within one degree) and there is almost no drift. After the one hour shear period the baseline tests seem to show little variation compared to those before. The variation is especially low at lower RPMs. Figure 3.7 shows the dial readings during the one hour shear period. This confirms that the drift in the equipment is negligible.

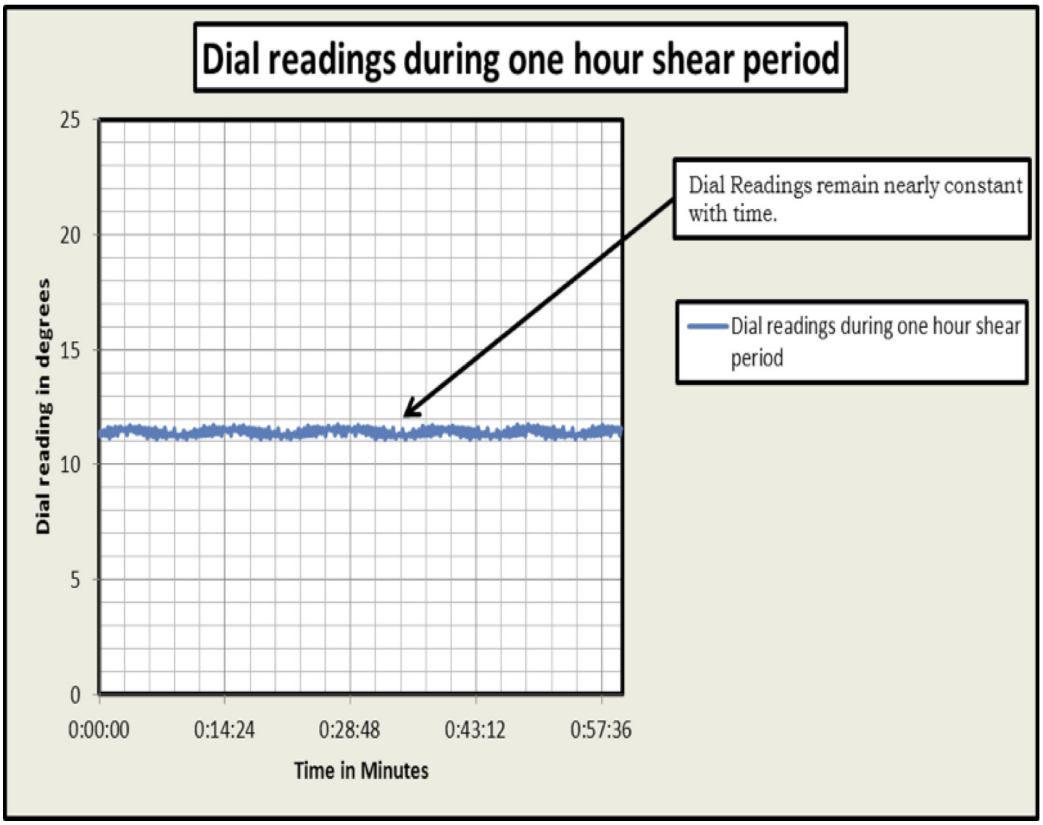


Fig. 3.7 – Dial Reading Variation During 1 Hour Shear Period

3.3 Sample Preparation

In order to ensure that the results are consistent over multiple experiments, a standard sample preparation procedure must be followed. The complex non-newtonian nature of the fluids being tested implies that the shear history and the degree of dispersion of clay particles in the suspension will have a major impact on the results of the test. If the fluid samples are prepared in a haphazard manner, the variation in test results must can be misinterpreted as arising from a change in fluid properties. Therefore, in order to eliminate shear history effects a fluid preparation protocol was followed.

The clay sample was first carefully weighed in an electronic weighing scale and then added to the required quantity of water. This mixture was then sheared for about five minutes in a high shear mixer. The clay was then allowed to prehydrate fully for about 16 hours. This allowed the clay particles to be fully disperesed and ensured that the clay had swollen to its maximum possible extent. The fluid was then sheared for a period of 30 minutes in a high shear mixer to ensure that the properties were uniformly distributed. Since all the samples were prepared in this manner their shear history and level of dispersion going in to the experiment were the same, this would mean that any difference in rheological response was due to the temperature and pressure conditions imposed.

This chapter presented the basics of the experimental equipment used for testing and the preparation rocedures selected for testing. A pilot test to determine viscometer drift characteristics was also discussed. The next chapter will discuss special testing schedule followed and the results obtained using this method.

CHAPTER IV

RESULTS AND DISCUSSION

This chapter presents the 'continuous test schedule' which is the main focus of this project. Two distinct testing schedules are followed in the experiments that are described below - the stepped test and the continuous rheological monitoring test. Detailed descriptions of these schedules are provided. The experimental results arising from following a continuous temperature profile and their implications are also presented.

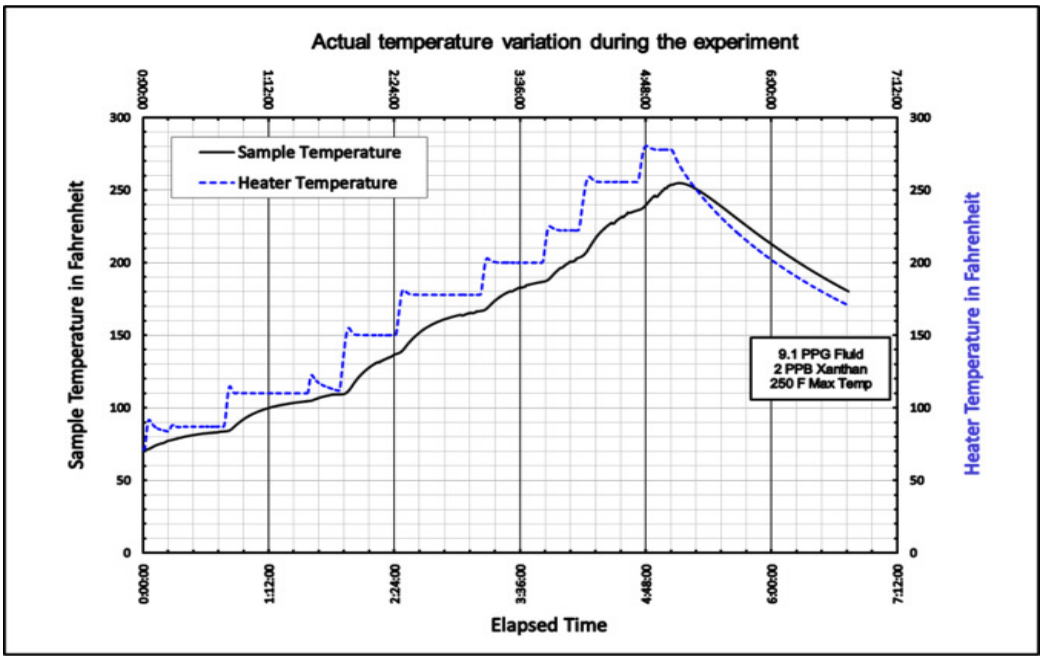
4.1 The Continuous Test Schedule

The traditional mode of testing drilling fluids involves stepped increases in pressure and temperature. The temeprature and pressure of the fluid is increased in steps and the fluid properties are recorded at each step. Typically a 'baseline' test is conducted at each of these steps and then the properties such as yield stress, fluid flow and consistency indices are calculated. This is useful in wellbore flow modelling simulation to obtain circulating pressures.etc. However, this mode of testing raises a few questions. Firstly, the temperature variation in a drilling fluid flowing through an annulus is *continuous* in nature. Since most drilling fluids are temperature history sensitive, the stepped temeperature profile may induce some errors in the measurements. Secondly, the baseline tests at each temeprature subject the fluid to very high rates of shear at each step. This itself may induce some shear history activated changes in the fluid rheology. For example, at 600 RPM the fluid is in a rate of shear that is experienced at the bit nozzles. This is not very representative of the constant rate of shear that

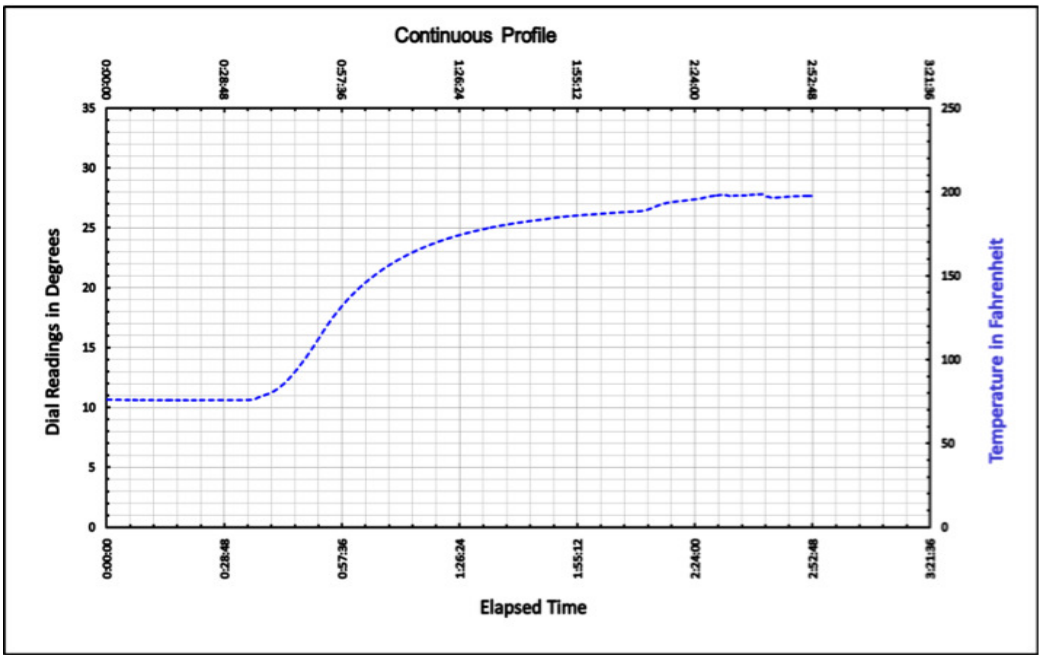
the fluid undergoes in the annulus. Therefore, a more *representative* mode of testing is required.

It is difficult to simulate the exact flowing temperature profile of a drilling fluid in experimental equipment, but very useful qualitative observations can be made by continuously monitoring the variation of a single rheological parameter as the fluid temperature changes according to a preset schedule. Such a real time observation of rheological properties will bring to light possible hydraulics issues at higher temperatures, especially those due to high temperature gelation of fluids having clay based viscosifiers. Such experiments may also enable the setting of operational limits or failure points for drilling fluids and help in planning fluid treatment schedules based on expected bottom hole temperatures. They can also provide useful insight into the actual behavior of drilling fluids in hot wells. The high rate of data output from the Chandler 7600 XHPHT viscometer makes this contnuous monitoring possible. By manipulating the temperature increase rate, the temperature history can be made to resemble the actual circulating profile of a drilling fluid in the flow loop. Figure 4.1 shows the difference between the stepped and continuous tests.

Based on the definition of a continuous test, a practical method of implementing the procedure in the viscometer to make real time observations of fluid flocculation and failure was formulated. One of the most important factors to take into account while testing fluids to failure is ensuring that the dial readings are manually monitored in real time to prevent damage to the equipment which may result from excessive thickening of the fluid under high temperatures. A step by step outline of the developed procedure is given below.



(a) Stepped Testing



(b) Continuous Testing

Fig. 4.1 – Comparison between Stepped and Continuous Testing

1. Prepare the fluid according to a preset protocol. In case of pre-formulated field muds, they are sheared in a high shear mixer for 15 minutes to eliminate barite sag effects and to make sure that rheological properties are uniform.

2. Load the sample in the test cell.

3. Determine maximum expected bottom hole temperature, based on local geothermal gradients or offset well data.

4. The maximum test temperature is set to be 25 to 30^{o}F greater than the above temperature.

5. Obtain fluid properties at a room temperature and pressure through a baseline test.

6. Increase the temperature continuously to 175^{o}F while shearing at 300 RPM and record the dial reading data.

7. Shear at 175^{o}F for 10 minutes and then increase the pressure to 5000 PSI. This is done to prevent steam generation at extreme temperatures.

8. Increase the sample temperature continuously to the temperature in STEP 4 while recording data.

9. Look for break points– defined as changes in the trend of rheological data, most likely an increase in viscosity preceded by a continuous decrease.

10. If the increase in viscosity is exponential, stop testing to avoid damage to viscometer. This means that the fluid has failed.

11. Otherwise, allow the temperature to increase to maximum limit.

12. Begin cool down cycle while recording data.

13. Identify changes in fluid during heating and cooling.

14. If there is exponential or rapid change in viscosity during cooling, stop testing, fluid has failed.

15. Otherwise, cool down to room temperature and obtain rheological properties again. The procedure is graphically described in Figure 4.2.

The continuous test schedule should, if implemented correctly, be able to provide valuable insights into changes in the properties of the drilling fluids that occur during more realistic reproductions of actual temperature histories. It is true that with the continuous availability of dial reading data during stepped testing, the fluid behavior in between temperature steps can be recorded. But, this is definitely not representative of the actual temperature history of a drilling fluid. The step changes in shear rates during the baseline tests at each step also compound the problem. Another important point to be noted is that, a continuous test cannot give the rheological parameters such as yield point. This requires that the fluid be tested at multiple shear rates. This seems to be a definite disadvantage. However, by shearing the fluid at approximately the same rate that is expected in the annulus a very definite qualitative assessment of fluid behavior can be made. This seems a better approach compared to interpolation of fluid properties between temperature steps which may not yield a good estimate of the temperature at which detrimental rheological transition occurs. This concept will become clearer with the presentation of data from actual experiments.

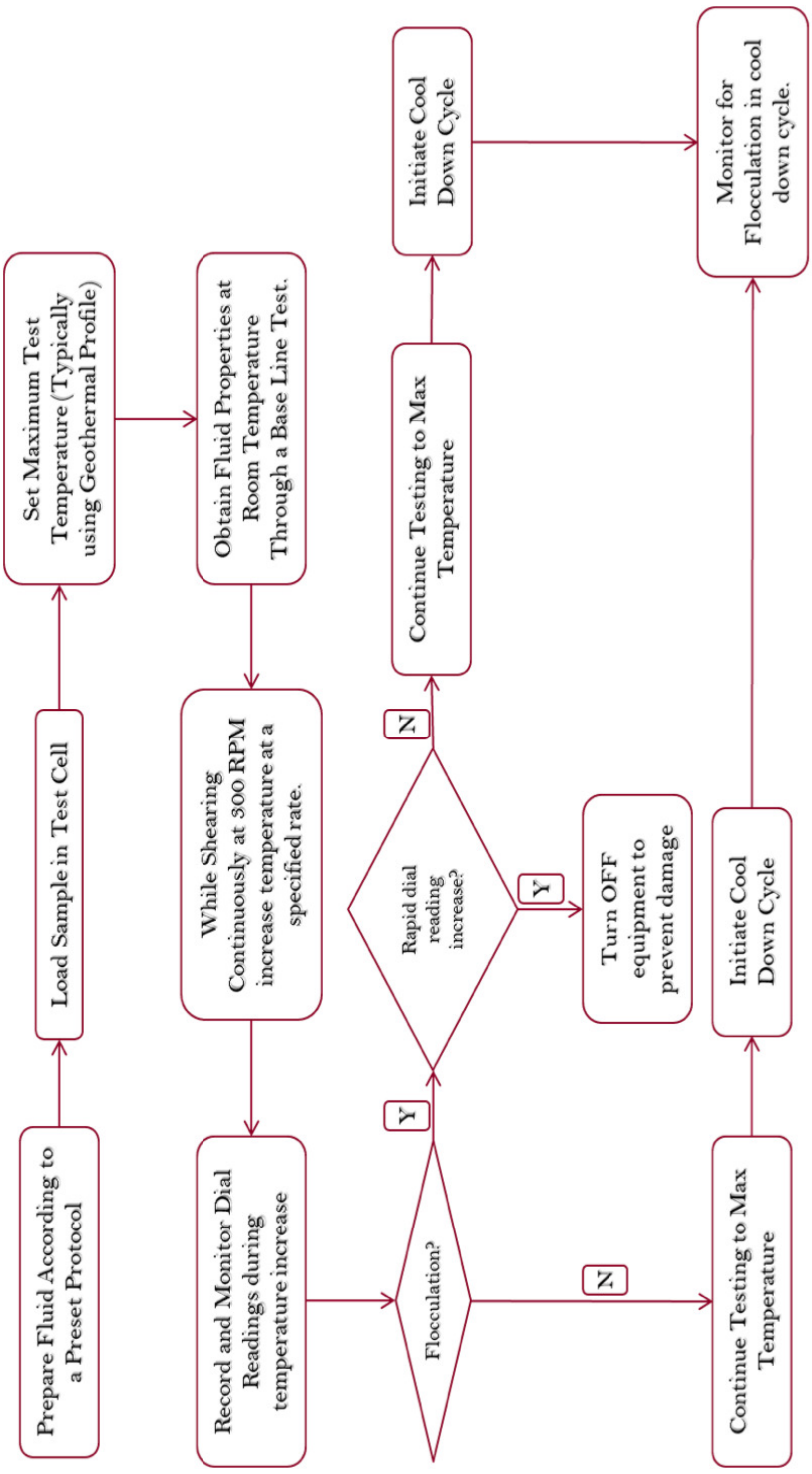


Fig. 4.2 – Schematic of Proposed Test Schedule

The following sections discuss the data obtained from rheological experiments conducted on a variety of mud frmulations. Only one stepped test is presented. The rest of the experiments involve continuous temperature variation. While continuous testing seems attractive on paper, only extensive experiments can definitively prove that it is a useful tool in fluid design. This will be the objective of the section that follows.

4.2 Experimental Results

An experiment was conducted on a 2 PPB solution of Xanthan gum in tap water to demostrate the usefulness of the stepped test. This type of testing will not be extensively discussed in the remainder of this thesis. The reader is requested to refer to Ibeh (2007) for a more detailed appreciation of the data from such tests. The solution was prepared by mixing the requisite amount of Xanthan gum after weighing in an electronic weighing scale with water and then shearing in a high shear mixer for about 20 minutes to ensure that the rheological properties are uniform and stable. It must be noted that water boils at 212^oF at atmospheric pressure and it would be impossible to measure rheological properties under such conditions. Thus, even though rheology of water based systems may be only weakly dependent on pressure, it becomes necessary to ensure that conditions of elevated pressure exist if high temperature rheological investigations are to be made. The temperature and pressure schedule of the experiment is shown in Table 4.1.

Due to issues with the pressure control system in the equipment, a precise control of pressure was not possible but, as noted earlier, it is evident from literature and from experimental data that the influence of pressure on rheology of water based muds

Table 4.1 – Temperature and Pressure Step Data

Step	Temperature	Pressure
1	75	0
2	80	700
3	100	2500
4	130	3700
5	165	5000
6	180	6400
7	200	7500
8	230	9500
9	250	11000

is negligible in comparison to that of temperature. It must be noted that an ideal temperature profile with the temperature of the fluid increasing linearly between set points and then remaining constant is impossible to achieve. In reality, the sample is heated by a computer controlled heating coil and the temperature of the coil does not increase linearly. The sample temperature which lags behind the heating coil temperature takes a lot of time to stabilize at the required point. Thus, the system is often programmed to begin baseline testing when the sample temperature is within 2.5 to 5^{o}F of the set point. The heater temperature stabilizes fairly quickly and the sample temperature takes more time. During the rheological baseline test too, the sample temperature is still increasing due to the flow of heat from the heater to the fluid, but the change in temperature is too low to introduce any serious error in the measurements. Another point to be noted is that the sample was sheared at 200 RPM during the transient periods when temperature was being varied.

Figure 4.3 shows the results of the experiment graphically. As it can be seen from the peaks of the dial reading curve, the fluid becomes thinner with temperature. One can also notice that when pressure is increased, there is almost no response in the dial reading curve, further reiterating the fact that pressures, especially below 20000 psig do not drastically alter rheological data. The system was allowed to cool down below the atmospheric boiling point of water before the pressure was manually released. The duration of the entire test was approximately 6 hours and 45 minutes. Gel strengths were not recorded during this test to reduce the overall testing time. An extremely important point to note is that there is absolutely no viscosity recovery during the cool down cycle after the stepped testing is complete. This gives us an indication of rheological hystersis that occurs in drilling fluids with cyclic variation of temperature.

4.2.1 Continuous Rheological Monitoring on a 25 PPB Bentonite Solution

The first continuous rheological test was performed on 25 PPB solution of bentonite. The objective of this test was to determine whether it is possible to determine with a reasonable degree of precision an operational limit based on rheology for drilling fluids. The fact that bentonite-water suspensions flocculate at high temperatures is a fairly well recorded phenomenon. In stepped test, this will be observed as an increase in dial readings at all shear rates after a critical temperature and an increase in the yield point of the fluid. This test was scheduled as follows:

- **Step 1:** Shear the sample at 300 RPM for 5 minutes.
- **Step 2:** Conduct a Base line rheology check and collect model data.
- **Step 3:** Begin continuous test procedure.

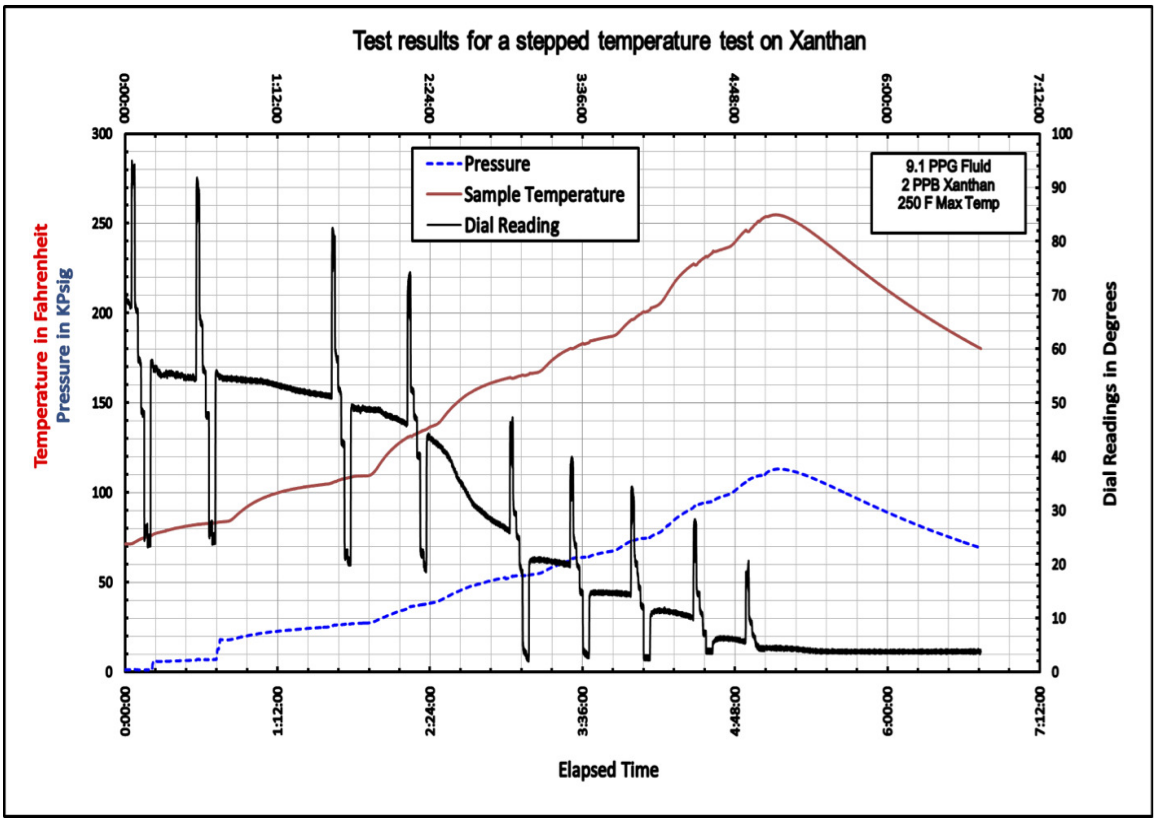


Fig. 4.3 – Overall Test Results for 2 PPB Xanthan Fluid

Figure 4.4 shows the results of the experiment graphically. It is clearly seen that after a certain temperature, the dial readings begin to increase and one can also notice erratic behavior in that there are instantaneous jumps. This suggests that the fluid sample has begun to flocculate. The test was stopped before the sample reached 200 F to avoid damaging the spring assembly. But, the general purpose of continuous rheological monitoring was achieved and changes in fluid properties were observed as they occurred.

It can be seen clearly that while the dial readings begin to increase at about 105^oF, the transition is smooth till about 135^oF when they start to become erratic. This may be due to individual flocs being sheared in between the bob and the rotor,

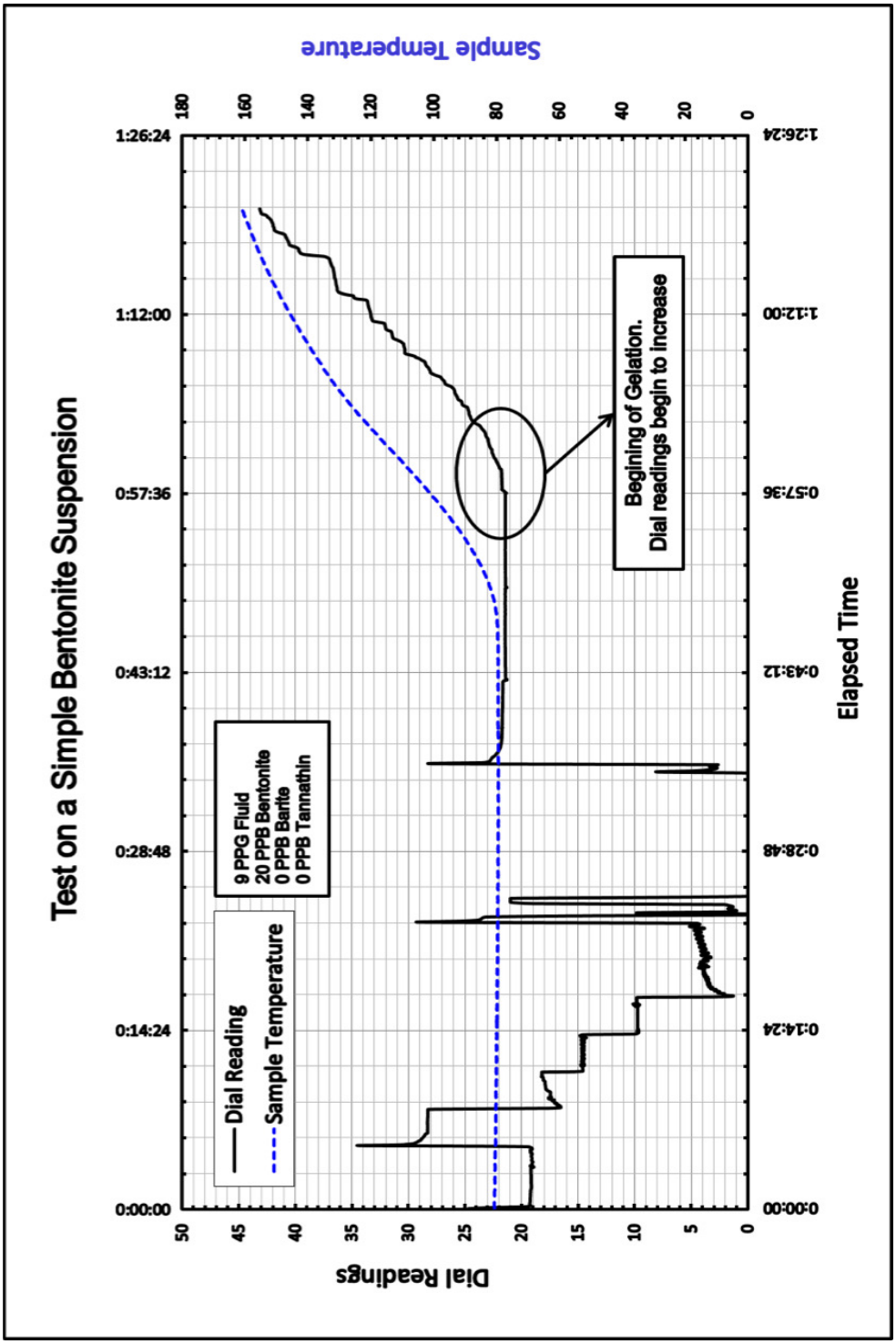


Fig. 4.4 – Overall Test Results for 25 PPB Bentonite Solution

causing the dial readings to jump. Thus, one can set an operational limit of about 135^{o}F for this particular formulation. The compositon of this fluid sample is exceedingly simple and is seldom seen is field use except when wells are being spudded. But, the objective of the of the test was satisfied in that the usefulness of continuous rheological monitoring was demonstrated. After the sample was allowed to cool down and the equipment was dismantled, the evidence of flocculation was clearly visible and the fluid sample could not be poured out of the test cell and had to be scooped out instead. This test proved to a great extent the utility of continuous rheological monitoring and confirmed that it could be implemented practically to produce meaningful results.

4.2.2 Test on 25 PPB Bentonite Suspension with Commercial Additive TANNATHIN

A similar experiment was performed on a 25 PPB suspension of Bentonite in water with 5 PPB of a commercial deflocculant TANNATHIN added to it. According to the product bulletin TANNATHIN "*is a secondary deflocculant and is especially effective in high temperature applications*" and "*it can be used in virtually any water based fluid*". TANNATHIN also reduces the viscosity and the gel strengths of the mud. Typical treatments range from 1 to 8 PPB. Its properties as per the product bulletin are summarized in Table 4.2

The experimental schedule was the same as the one before with the maximum temperature of investigation being 200^{o}F. The results of the experiment are shown below in Figure 4.5. In this particular experiment there is no sign of flocculation occurring and unlike the previous case, there was no risk of damage to the spring assembly due to continuous increase in dial readings. The 300 RPM dial readings remained

Table 4.2 – Properties of TANNATHIN

Specific Gravity	1.6 - 1.8
pH(1 % solution)	4-5
Bulk Density	52 $\frac{lb}{ft^3}$
Grind	90 - 95 $<$ 20 mesh

fairly constant throughout the test. In fact, a dip was observed in the dial readings as the temperature initially increased. The addition of TANNATHIN seemed to have thinned the fluid down reducing its viscosity as mentioned earlier. The results of the rheology check at room temperature and at the final temperature of 200^{o}F seem to be similar, with no observable change in rheological parameters. Thus, the treatment has made the fluid is more rheologically stable than the previous case. These two tests seem to prove the ultimate utility and practical applicability of continuous rheological testing. Also the behavior in between the two baseline tests (thinning and slight thickening) would have been difficult to observe in the case of stepped testing.

The behavior of these two fluids is radically different and one can expect a similar phenomenon to occur during actual drilling operations too. While these tests are good indicators of fluid performance, the fluid samples have a very simple composition. Actual Drilling fluids often have many additives for different functions. Figure 4.6 shows the comparitive performance of these two fluids.

4.2.3 Tests on More Complex Fluid Formulations

After gaining confidence in the new testing procedure, more complex fluid formulations were tested. This was done to see if the point at which the fluid flocculated had any relation to the composition of the fluid provided that the same amount of Ben-

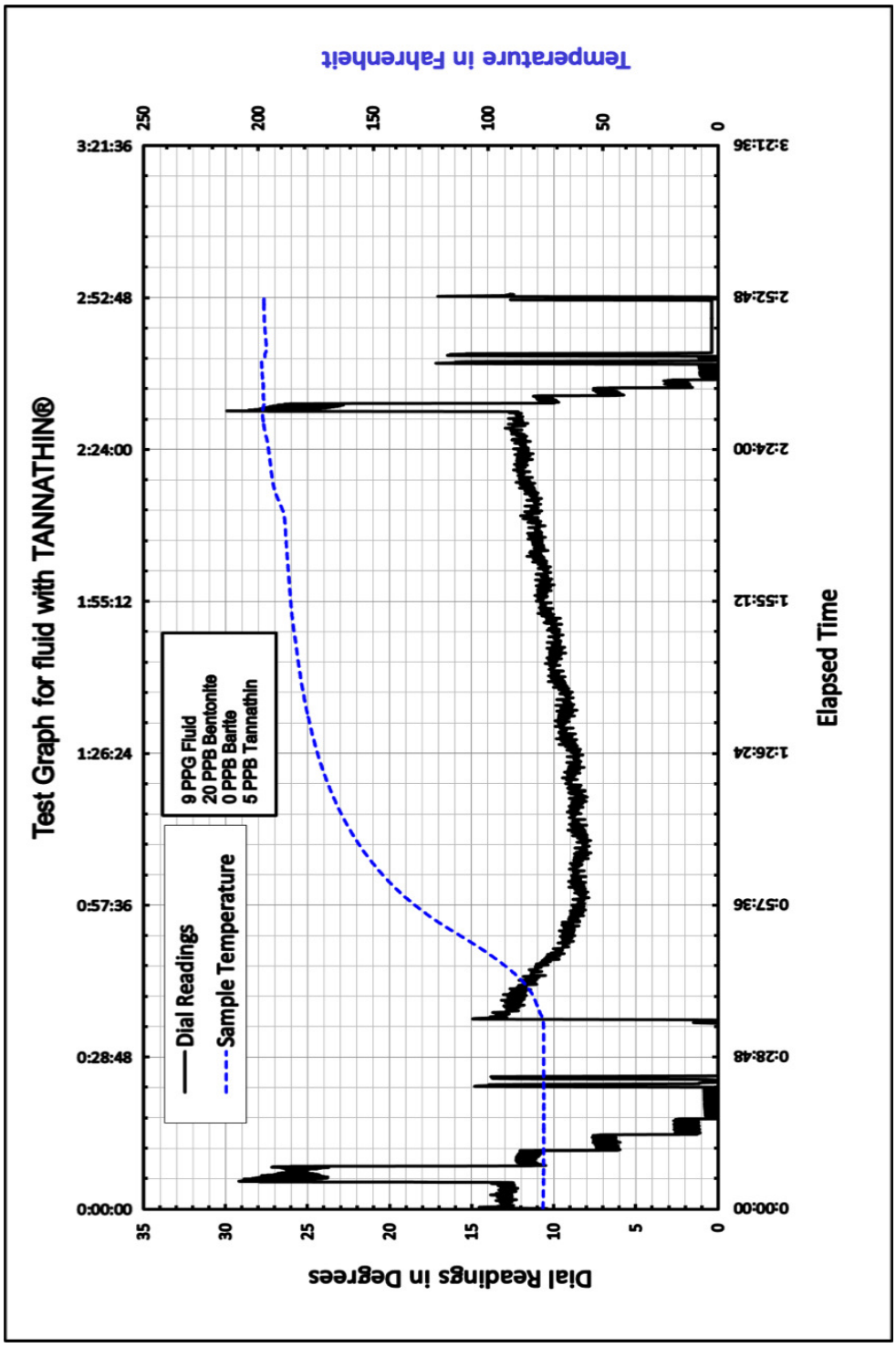


Fig. 4.5 – Overall Test Results for 25 PPB Bentonite with TANNATHIN

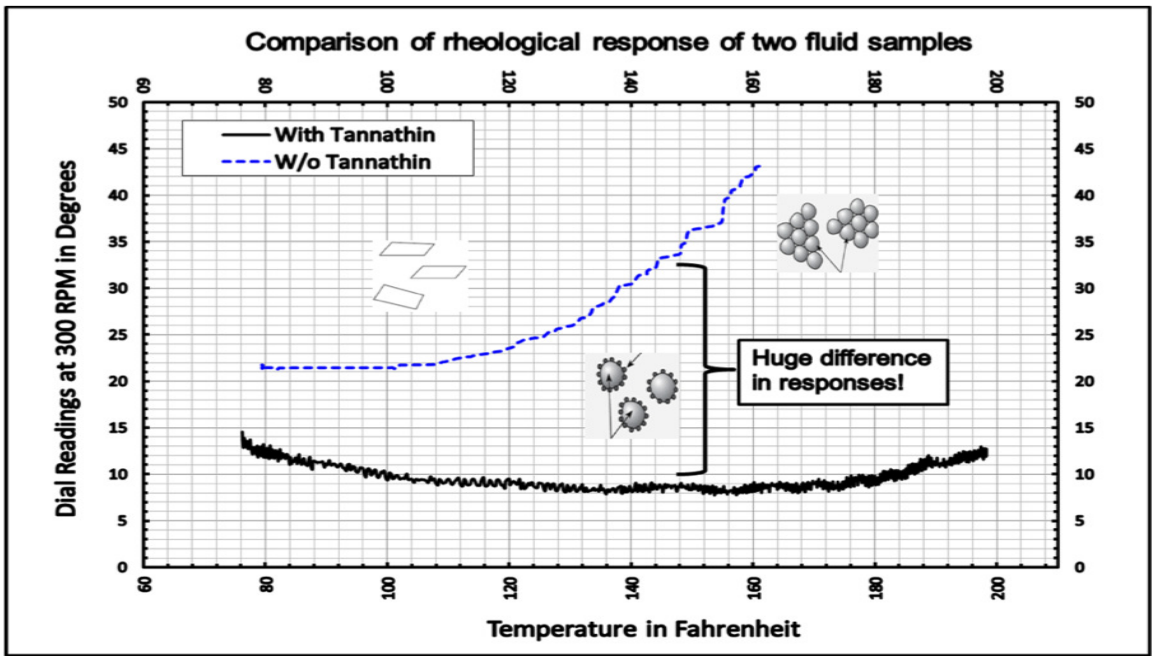


Fig. 4.6 – Comparison of Rheological Response of Two Bentonite Solutions

tonite and deflocculant were used. These tests were more extensive in that the testing procedure also included a cooling cycle to see if there was any significant difference in the rheological response during the heating and cooling cycles. All drilling fluids were weighted with barite so that they could exert sufficient hydrostatic pressure on the formation to prevent a fluid influx. The maximum temperature of the test was also increased to reflect conditions that may be expereinced in UHPHT wells. The general fluid compositon is given in Table 4.3.

Table 4.3 – Composition Table for Weighted Fluids

Component	Concentrtion
Bentonite	25 PPB
Deflocculant	5 PPB
Barite	Variable

In the interest of brevity the detailed results of only one of these tests is presented here. The test chosen was for a fluid having a density of 10 PPG , containing 60 PPB of barite in it. The maximum temperature of investigation was 450^{o}F. The pressure was also increased with temperature to ensure that there was no steam generation in the test cell. Pressure doesnot have too much of an influence on the fluid rheology, so its effects can be ignored without any risk. The fluid was not allowed to cool down to room temperature, but test was stopped when the temperature of the fluid reached 200^{o}F on the cooling cycle to avoid operating the machine for extended periods of time. The cooling cycle is typically much slower than the heating cycle since the test cell is air cooled.

The results of the experiment are presented in Figure 4.7. Fluid flocculation is clearly visible after a certain tempeature is recached and the fluid thickens considerably with more than a 50 % increase in dial readings. This is a definite indicator of the rheological transition from dispersed to the flocculated state. If this fluid was used in a UHPHT well with the current level of treatment, then problems can be expected to occur. During the cooling cycle a drop in the dial readings is seen initially but, the dial readings then begin to increase rapidly and it is immediately observable from the baseline test conducted at 200^{o}F that the fluid that has changed irrerversibly from its initial state. This hysterisis effect must be taken into account when drilling wells and the fluid must be treated accordingly. The current fluid is clearly unsuitable for drilling UHPHT wells considering the huge change in rheological properties with temperature. This is an example of how continuous testing can be used to fine tune the fluid design process in ways that stepped testing cannot.

The hysterisis effect is more clearly visible in the temperature vs dial reading graph

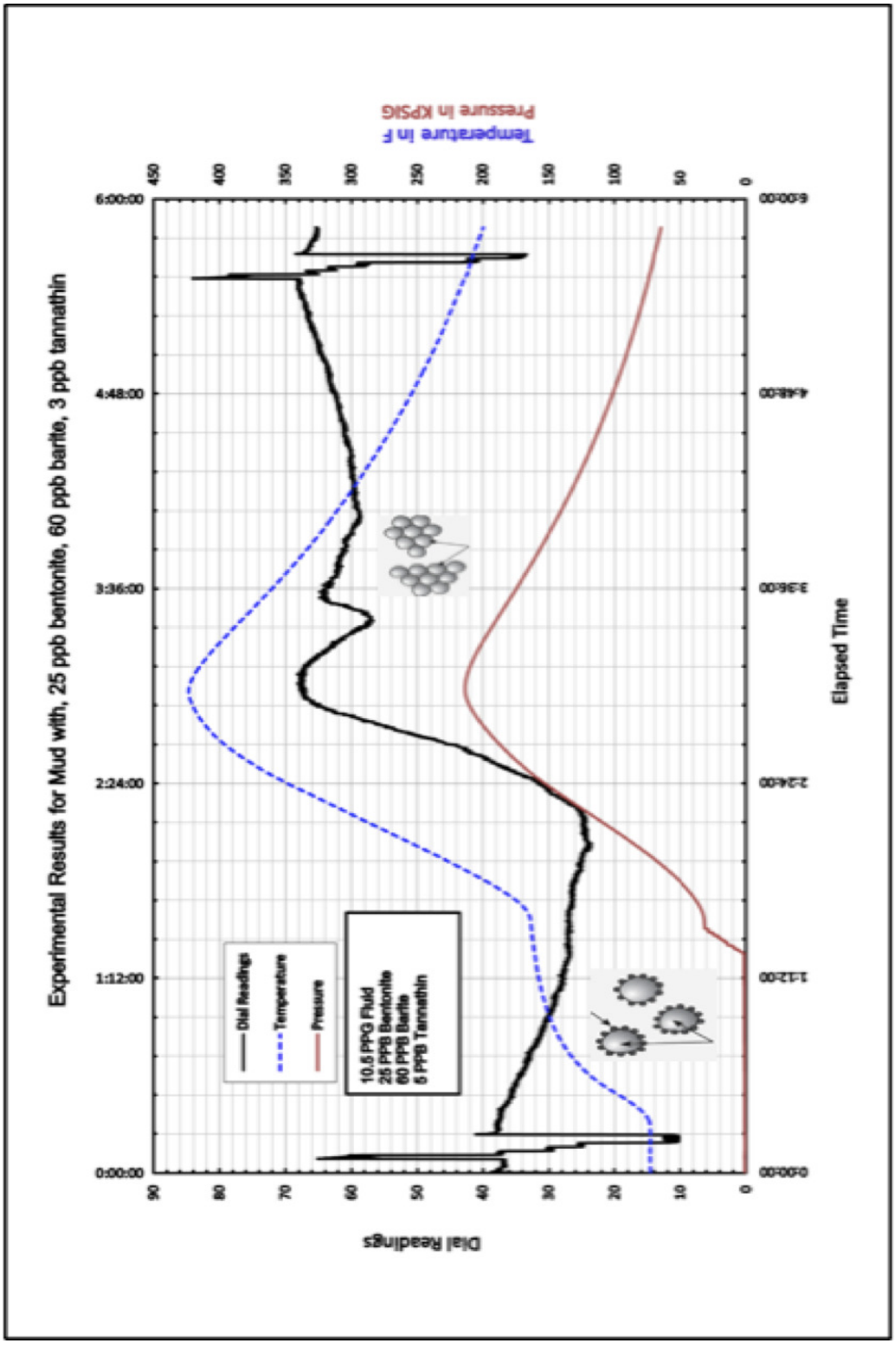


Fig. 4.7 – Overall Test Results for Fluid with 60 PPB Barite

shown in Figure 4.8. The magnitude of the difference in the dial readings confirms the fact that an irreversible chemical change has occured in the fluid to an extent that cannot be overlooked and chemical treatment is necessary to ovecome adverse effects.

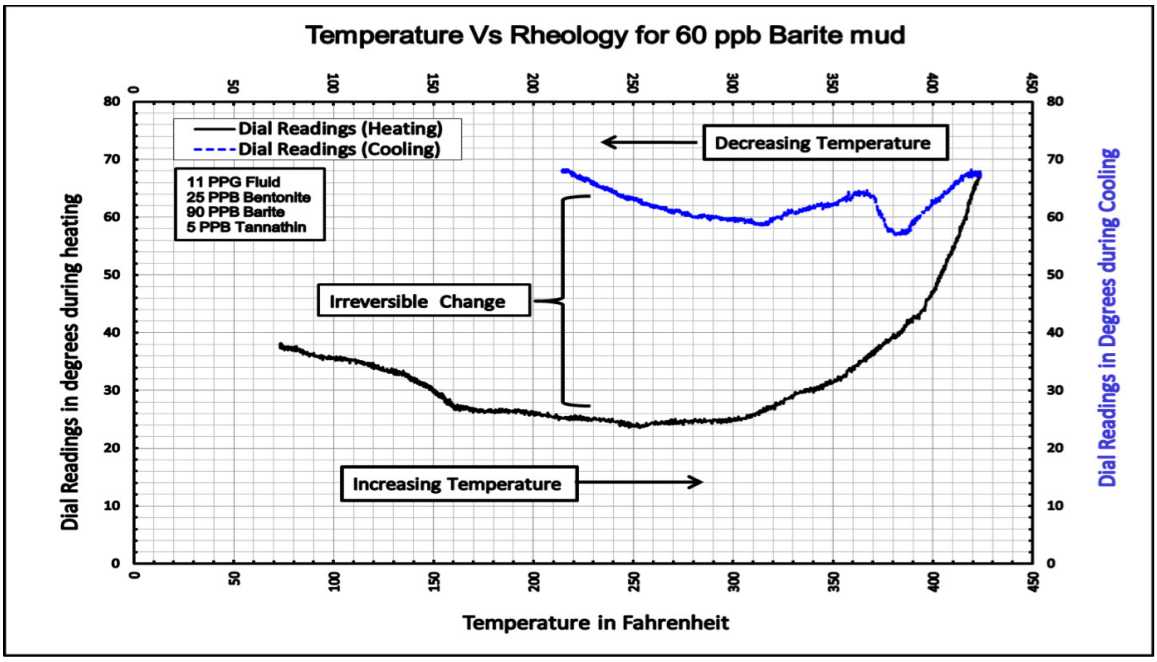


Fig. 4.8 – Temp. vs Dial Reading Graph for 60 PPB Barite Solution

A series of such experiments were conducted on fluids of varying barite content. Figure 4.9 shows the temperature vs dial reading graph for these fluids. One thing that can be immediately noticed is the fact that with *increasing barite content, the temperature at which rheological transition takes place decreases.* This is a very important observation, which seems to suggest that treatment of Water Based Muds should be based on not only the expected temperature of operation, but also on the total solids content. The reason for this behavior is not immediately clear, but it is plausible that the deflocculant particles are 'consumed' by other non-reactive solid particles other than clay and may thus be rendered ineffective with increasing non-reactive solids

content. This is however only a conjecture unspported by detailed chemical analysis. The important fact is that continuous rheological testing has enabled the detection of this effect, which speaks volumes of its utility.

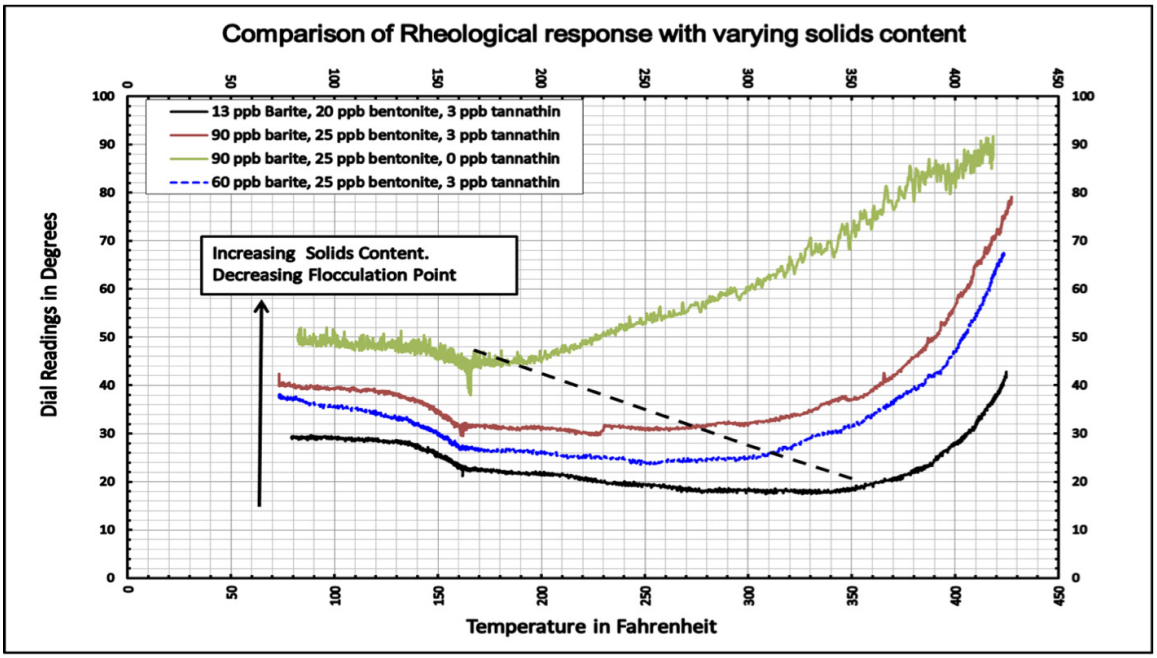


Fig. 4.9 – Effect of Solids Content on WBM Flocculation Temperature

These experiments were performed again on the same set of fluids to ensure that the results were repeatable and consistent. The graph of the 'rheological transition' temperature versus the barite content of the fluid is presented in Figure 4.10. It is seen that the results of both sets of experiments are very similar and a definite trend can be observed with respect to flocculation temperatures.

Another set of experiments was conducted on fluids containing Spersene - a commercial fluid loss additive that doubles as a deflocculating agent. The lime content in these fluids was varied to determine if there was any effect on the lime content on the rheological transition temperature. As expected, there is a similar effect to that of

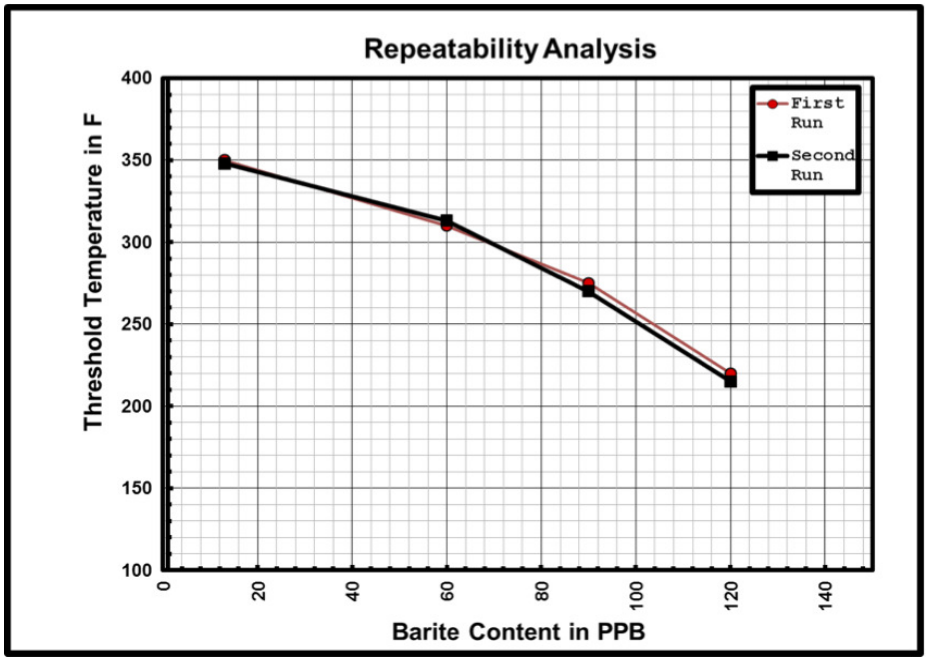


Fig. 4.10 – Repeatability Analysis for Sensitivity Tests

barite addition. An increase in lime concentration decreases the temperture at which the 'viscosity hump' is observed. Figure 4.11 shows this effect.

4.2.4 Tests on a Field Mud

After testing lab prepared fluid samples, a water based mud of density 18.4 ppg used in drilling a deep onshore well of depth 17800 ft was tested using the same procedure. This was done to determine if extremely complex fluid formulations would also show the visible rheological transition that was observed in the simpler lab prepared samples. The properties of this fluid are listed in Appendix B.

After conducting a few pilot tests at lower temperatures to ensure that the mud was in good condition , it was first subjected to a continuous rheological test with the maximum temperarture being 400°F. Figure 4.12 shows the rheological response of the fluid during the heating and cooling cycles. As it is seen from the graph, there

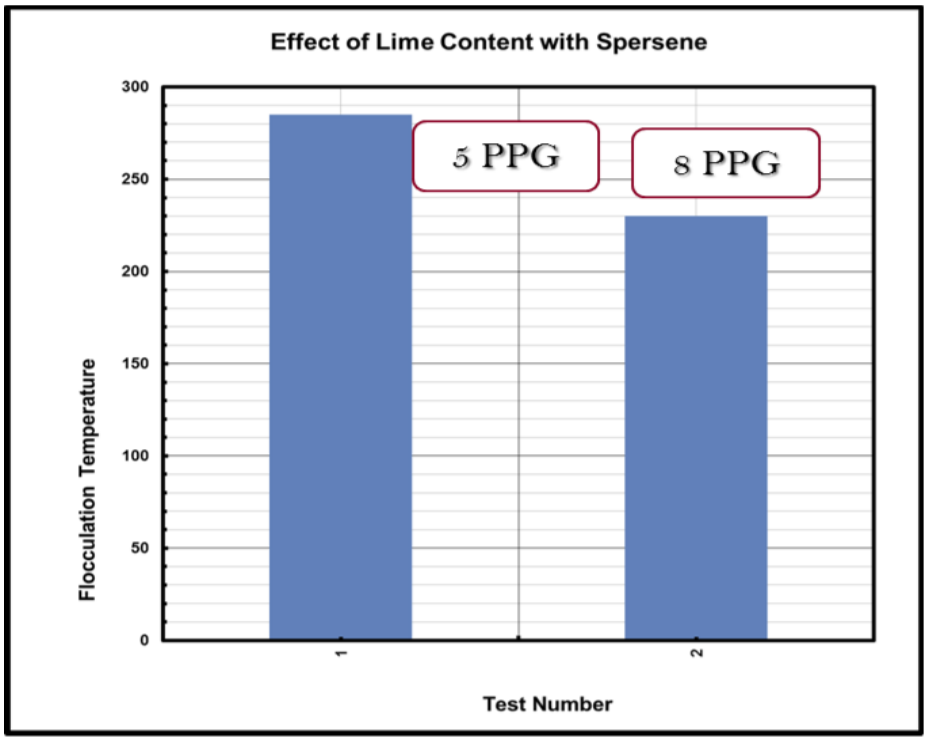


Fig. 4.11 – Effect of Lime Content on Flocculation Temperature

is a clear change in the rheology of the fluid at about 270^{o}F with the dial readings increasing rapidly after this point. This indicates that the clay-based viscosifiers in the fluid have begun to flocculate and that the fluid is thickening. Such a direct observation of rheological change would have been difficult to make when testing the fluid in steps. During the cooling cycle, the fluid begins to lose viscosity initially, but then thickens with further reduction in temperature. Eventually, the dial readings in the cooling down cycle are higher than in the heating cycle, indicating permanent rheological change. However, the magnitude of change doesnot seem to indicate any immediate need to treat the fluid. This fluid can be used to drill further as it indeed was (the maximum temperature in the well it was used to drill was 375^{o}F).

A baseline test was conducted at the begining of the heating cycle and at the end of the cooling cycle. The results of these tests show a definite change in the rheology

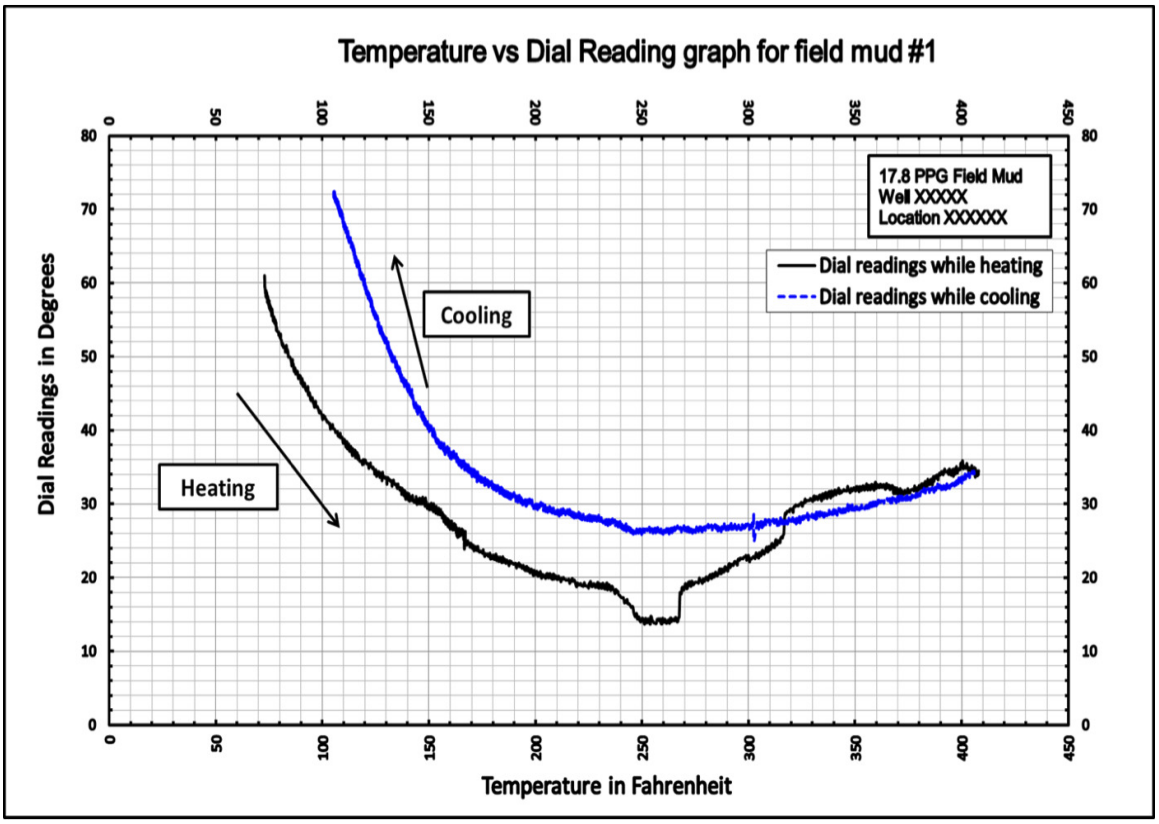


Fig. 4.12 – High Temperature Test on Field Mud at 400F

of the fluid especially at lower shear rates. Yet again, it must be emphasised that the change is not drastic enough to demand immediate fluid treatment. Figure 4.13 shows the comparison of dial readings.

In order to validate the results of the previous experiment, another continuous rheological test was conducted, on the same fluid. This time however, the sample temperature was increased to 450^{o}F to see if there was any effect of further increase in temperature on the fluid properties. The schedule was otherwise the same as that for the previous test. Again, there is an increase in dial readings noticed at around 260^{o}F, as noted previously. However, in this case there is a significantly different behavior during the cooling cycle, when the dial readings begin to increase at a tremendously

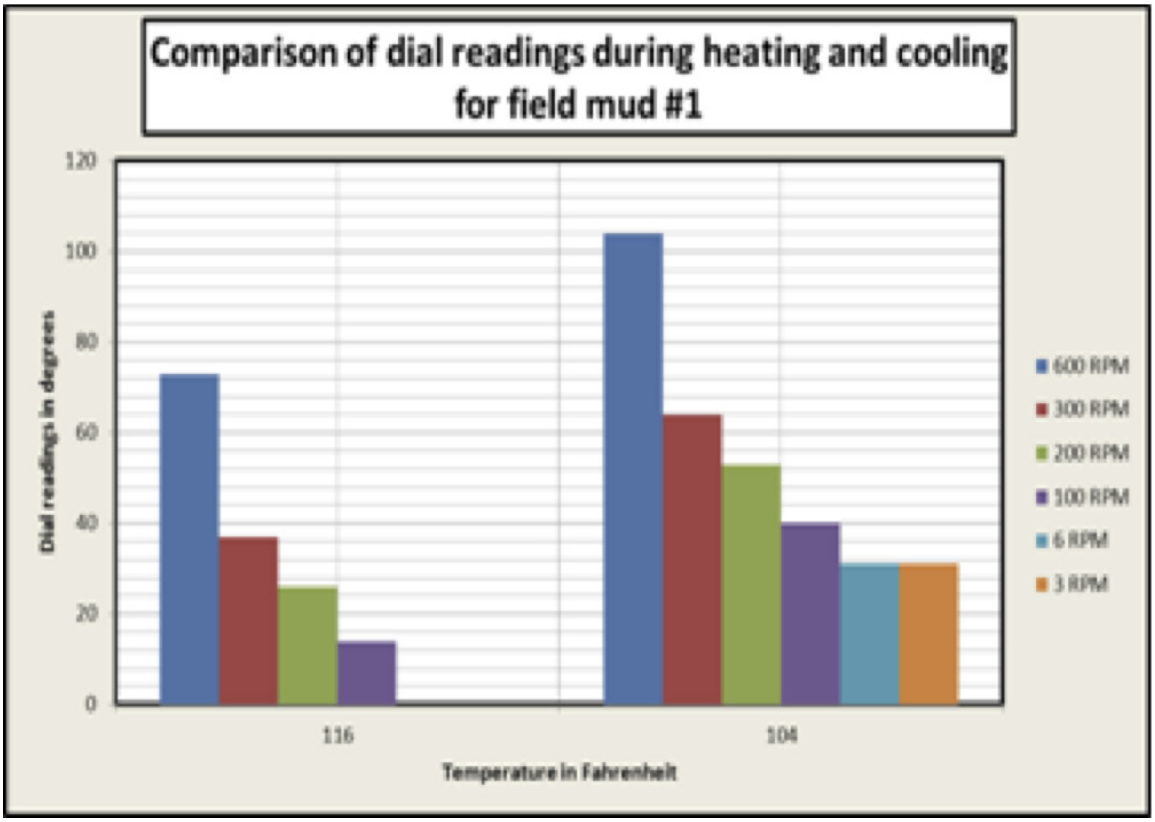


Fig. 4.13 – Hysterisis Effect for Field Mud

rapid rate at about 425^{o}F. This suggests that exposure to a maximum temperature of 450^{o}F has caused to the drilling fluid to fail. Such a response was not observable in the previous test. The testing was then stopped during the cooling cycle at around 395^{o}F to prevent any damage to the rotor. After the sample had cooled down to 150^{o}F the fluid sample was retrieved and it had undergone such a dramatic change that it could not be poured out. Figure 4.14 shows the variation in dial readings with temperature during heating and cooling in this test.

Thus, continuous testing of the drilling fluid at two different maximum temperatures provides another very interesting result. A slight increase in the maximum temperature of investigation drastically changes the behavior of the fluid during the

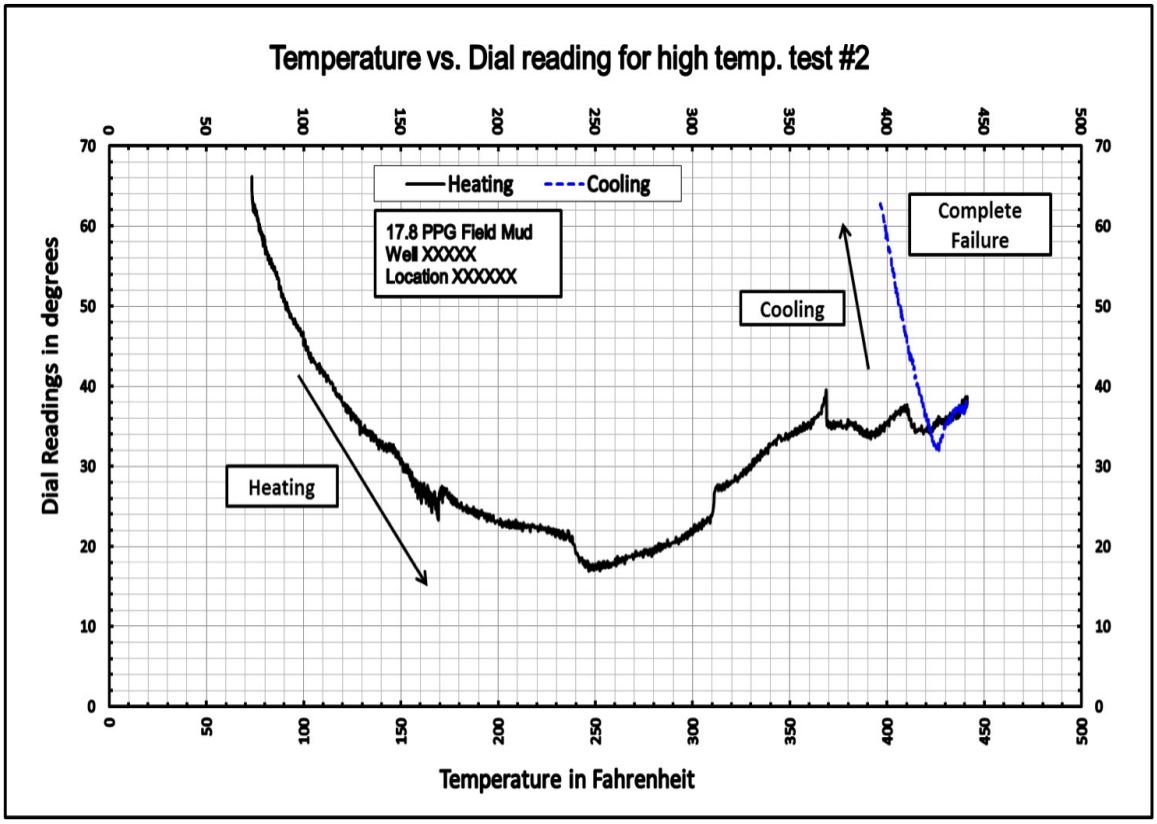


Fig. 4.14 – High Temperature Test on Field Mud at 450F

cooling cycle. This will have to be accounted for during the fluid design process and must be accounted for in experimental studies. Any extension of the operating limit of the drilling fluid must be carefully considered before proceeding further. It is recommended that such extended temperature tests be conducted to overcome any contingency situations. Figure 4.15 shows the completely failed fluid sample that resulted from the second continuous test on the field mud.

4.2.5 Cyclic Testing of Drilling Fluids

On a more practical level, fluid degradation may not be so dramatic and sudden, but instead may occur over several cycles of circulation. To account for this, a cyclic test procedure was designed to mimic the temperature experience of a fluid that is

Fig. 4.15 – Completely Failed Fluid Sample

circulated in and out of a well bore. The results seem to indicate that fluid treatment in UHPHT wells needs to be a continuous process. One such test is shown in Figure 4.16, indicating a less rapid but significant fluid degradation. The fluid had 90 PPB of Barite and was loaded with 10 PPB of TANNATHIN to prevent early failure of the fluid during the first cycle itself. This stage of the project is ongoing as we are not yet confident that the equipment can tolerate such prolonged (greater than 24 hrs) exposure to extreme conditions.

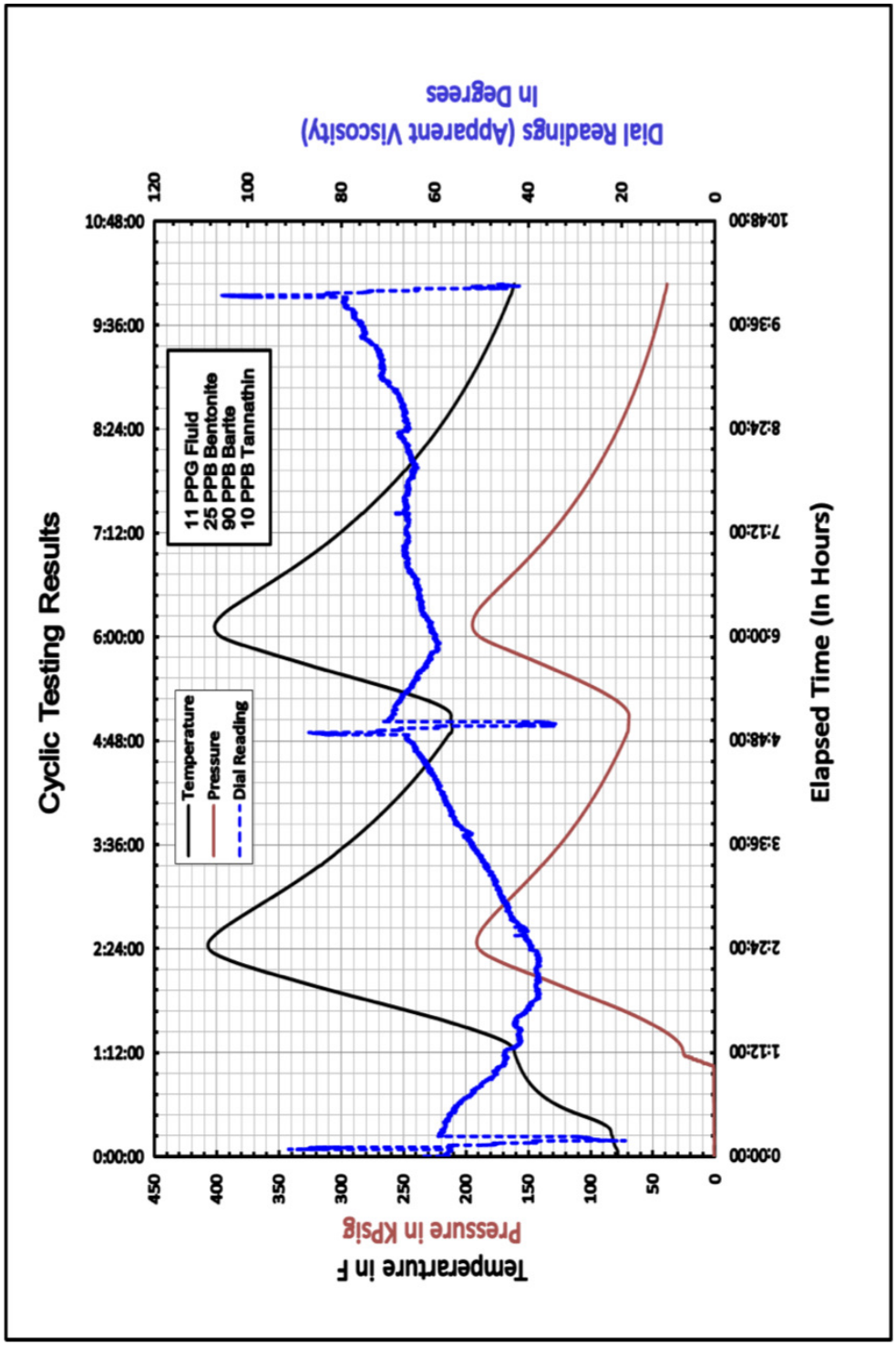


Fig. 4.16 – Results of Cyclic Testing

4.3 The Bigger Picture

The question that must be asked at the end is, where does the program of continuous rheological testing fit into the larger picture of Water Based Mud Design? Given the obvious advantages of this testing procedure it can definitely be performed along with stepped testing with minimal cost and time. Considering the range of new data and insight that it gives into fluid behavior at high temperatures, it may be a significant addition to the fluid engineers repertoire. Figure 4.17 gives a graphical description of how real time rheological monitoring fits into the processes that constiture fluid design.

This chapter presented the rationale behind using the continuous procedure to test drilling fluids. The procedure was then validated using a series of tests whether the proposed testing schedule is worth the effort in terms of the usefulness of its output. The results were found to be encouraging and merit more detailed investigation in future projects.The following chapter briefly lists the conclusions of this research projecty along with recommendations for future work.

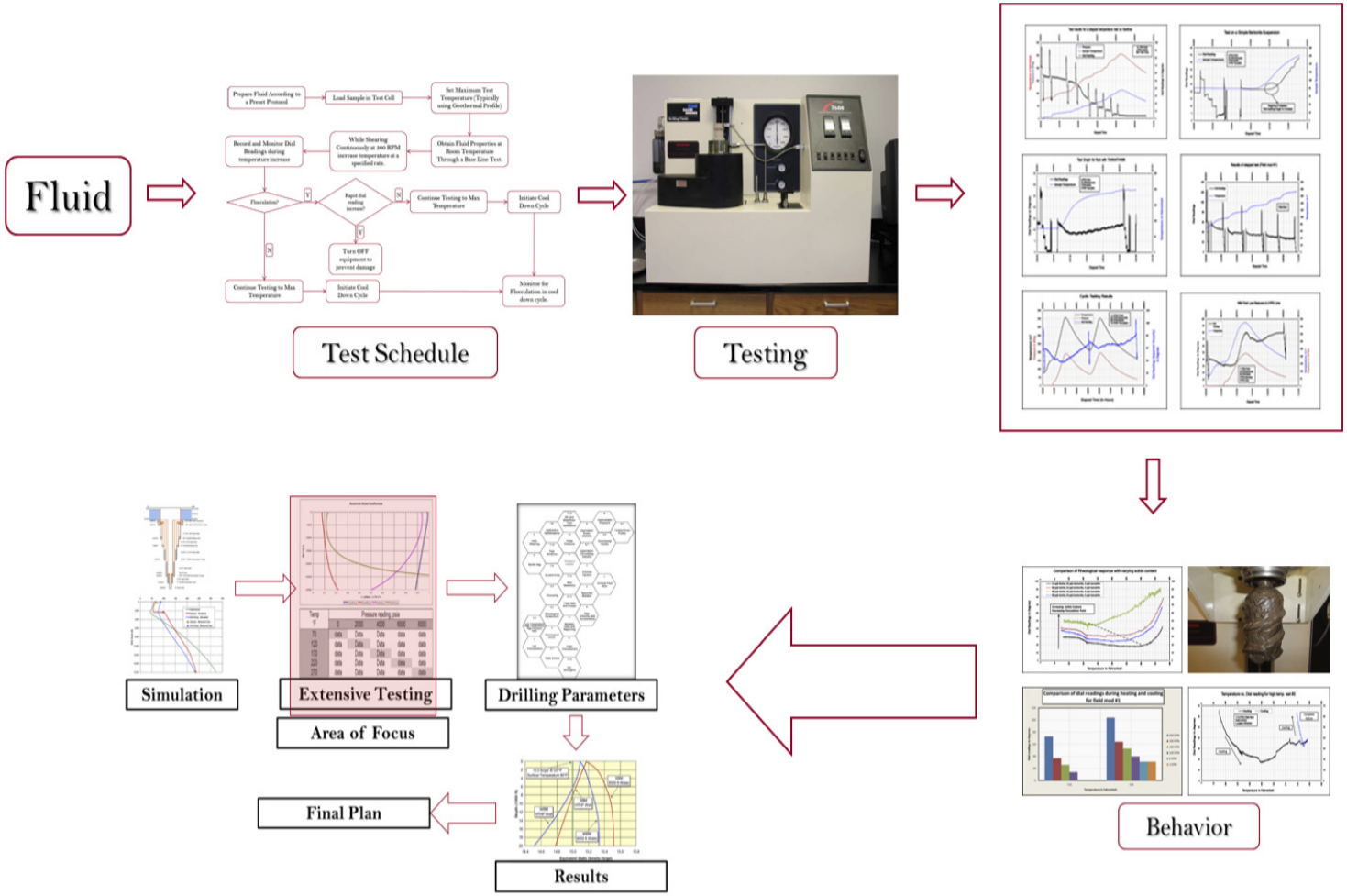


Fig. 4.17 – Application of Continuous Testing in the Overall Fluid Design Process

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

Based on the experimental test data that has been presented, the following conclusions can be drawn:

- HPHT wells require a much more detailed fluid design process when Water Based Muds are being used.
- The colloidal chemistry of clays has a significant influence on the behavior of Water Based Muds at elevated Temperatures.
- Continuous rheological testing of Water Based Muds can reveal aspects of fluid behavior that may not be immediately noticeable in stepped tests. Over 100 hours of continuous test data has been collected to backup this claim.
- In fluids containing clay based viscosifiers, the temperature of flocculation is affected by the concentration of solids present in the fluid.
- Whether a drilling fluid fails in a high temperature well seems to be dependent on the maximum temperature that the fluid experiences in its temperature history.
- Cyclic testing of drilling fluids can indicate the gradual degradation of drilling fluid peoperties with time and these results can be used to plan appropriate fluid treatment schedules.

The current work has significant scope for improvement and extension in the future. Some recommendations related to equipment redesign and future experimental testing are presented below.

- The fluid tests can be extended to accomodate even more complex mud formulations thereby quantifying the effect of each component on high temperature behavior.
- Determination the effect of gas influx on water based drilling fluid rheology through modification of the rheometer to include a high pressure gas injection system.
- Modification of the Viscometer to include artificial cooling to incorporate longer cyclic tests. The benfits of this will be significant as much more realistic cyclic tests can be performed.

In conclusion it can be said that Water Based Fluid design for Ultra High Temperature operations is not a trivial task. It is a complex optimization problem that has to take into account several factors and influences. Extensive fluid testing with updated and innovative testing schemes will aid tremendously in quantifying some of the unknowns in this optimization problem. This will inturn enable faster, safer and deeper drilling operations with Water Based Muds.

NOMENCLATURE

HTHP – High Temperature and High Pressure

BHST – Bottom Hole Static Temperature

BHSP – Bottom Hole Static Pressure

NPT – Non Productive Time

WBM – Water Based Mud

OBM – Oil Based Mud

RPM – Revolutions Per Minute

PPG – Pounds Per Gallon

PPB – Pounds Per Barrel

SBM – Synthetics Based Mud

SPE – Society of Petroleum Engineers

UKCS – United Kingdom Continental Shelf

API – American Petroleum Institute

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APPENDIX A

FLUID MODELS

The purpose of this section is to present a very brief introduction to the various commonly used non-newtonian fluid models in the drilling industry. Since non-newtonian fluids donot have a shear stress that is directly proprtional to the shear rate of the fluid, there exists a need to quantify the relationship between shear rate and shear stress through specific equations known as fluid models. It must be noted that most water based drilling fluids are *shear thinning* in nature. Their viscosity reduces with shear rate. They also show time dependent rheological behavior known as thixotropy. This is responsible for the increase in the viscosity of the fluid when it is at rest and manifests itself as *gel strength*. Three of the most common fluid models along with their governing relationships are presented below in Table A-1.

Table A-1Common fluid models

Model Name	**Governing Relation**
Bingham Plastic	$\tau = \tau_y + \mu_p \gamma$
Power Law	$\tau = K\gamma^n$
Herschel-Bulkley	$\tau = \tau_y + K\gamma^n$

Where, τ - Shear Stress

τ_y - Yield Stress

γ - Shear Rate

μ_p - Plastic Viscosity

K - Fluid Consistency Index

n - Fluid Flow index

APPENDIX B

DETAILED TEST RESULTS

The purpose of this appendix is to present in detail, some results of the tests that were omitted from Chapter IV in order to maintain brevity or provide more detailed graphs of tests that were not discussed in detail.

Figure B-1 describes the variation in dial readings as the temperature of the sample is increased. It is clearly seen that the yield stress decreases with temperature, with a large drop seen in between 130 and 165 oF. At 250 oF, the calculated yield stress is only about 20 % of that at room temperature. The value of the parameter K also drops to very low values at higher temperatures. Figure B-2 shows the H-B rheograms at various temperatures drawn using the calculated parameters it is noticeable that as the temperature increases, the rheograms become more and more linear, eventually the value of the n parameter becomes 1 which essentially implies that the fluid now behaves as a Bingham plastic. Figure B-3 shows the variation of dial readings with temperature for the 25 PPB unweighted bentonite solution that was initially tested. Figure B-4 shows the difference in the rheograms of the two fluid samples that were subjected to the continuous test schedule. It is clearly noticeable that the fluid with the deflocculant shows more or less newtonian behavior with lower viscosity. Table B-1 shows the properties of the field mud that was used in continuous testing.

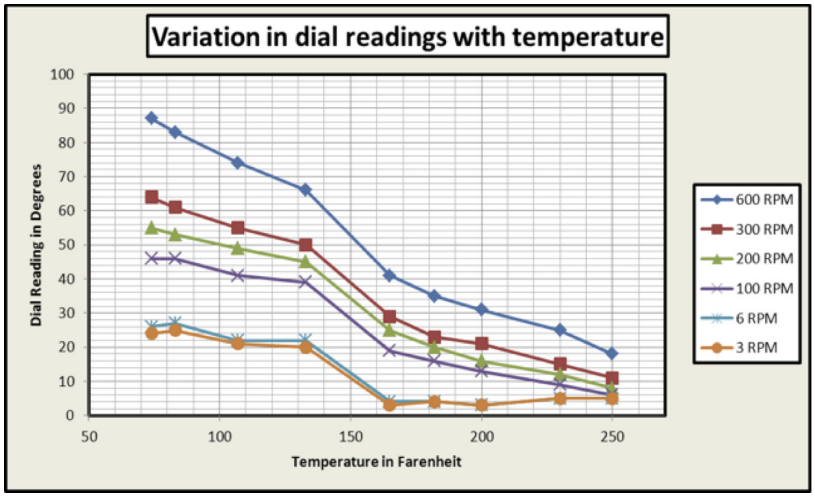

Figure B-1 Variation of Dial Readings in Xanthan Stepped Test

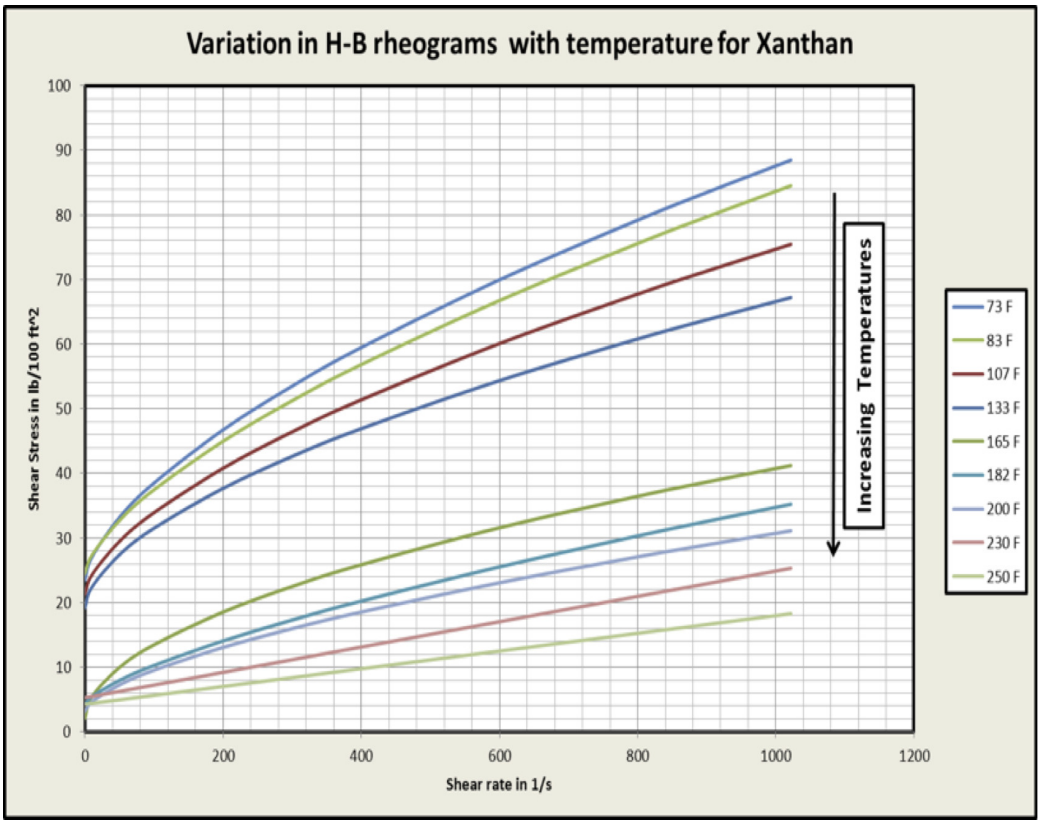

Figure B-2 Variation of Rheograms in Xanthan Stepped Test

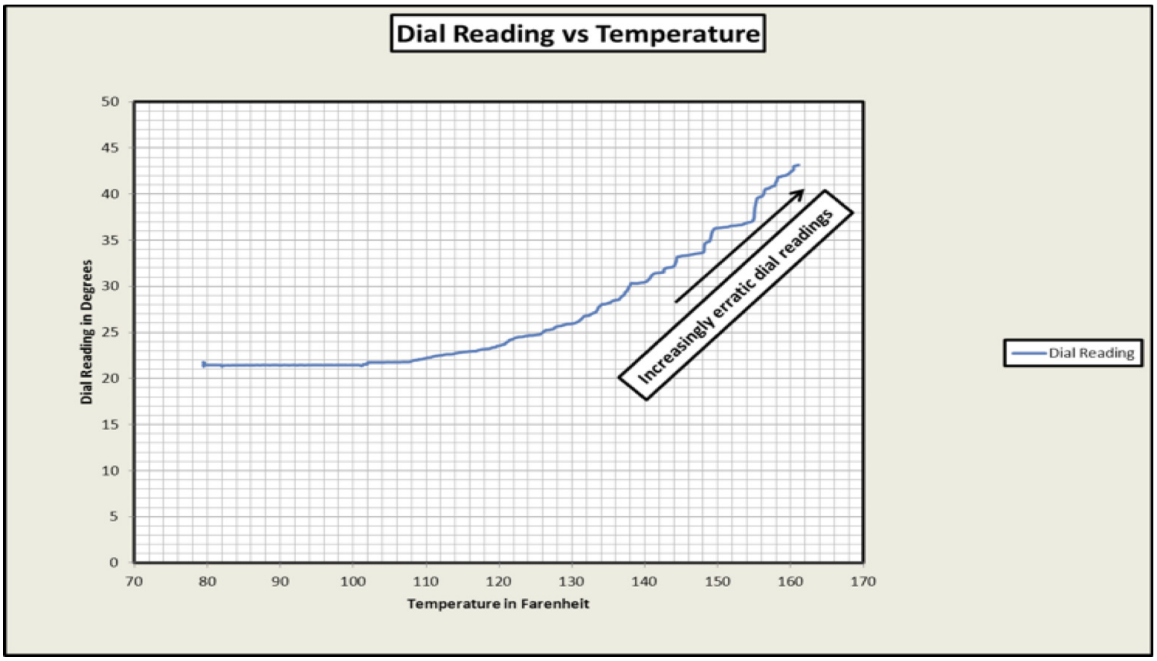

Figure B-3 Variation of dial Readings with viscosity for 25 PPB Bentonite

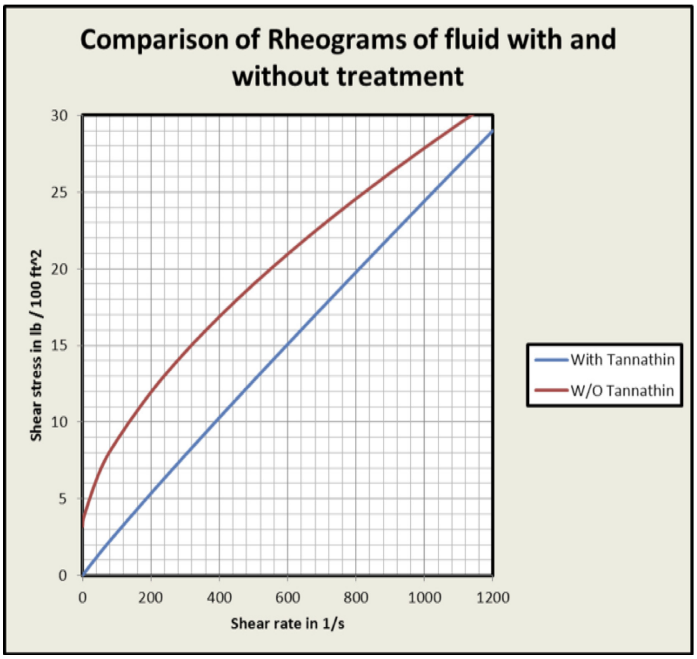

Figure B-4 Comparison of rheograms of treated and untreated Bentonite

Table B-1 Properties of Field Mud Used in Testing

Mud Weight, lb/gal	17.8	**Bentonite Equivalent (MBT), lb/bbl**	10
Fluid Phase Type	Fresh Water	**Water, % by volume**	63
Rheological Properties @ 120°F		**Oil, % by volume**	0
600 rpm reading	75	**Solids, % by volume**	37
300 rpm reading	43	**Dissolved Solids, % by volume**	0.01
200 rpm reading	31	**Corrected Solids, % by volume**	36.99
100 rpm reading	19	**Weight Material, SG**	4.2
6 rpm reading	4	**Oil, SG**	0.87
3 rpm reading	3	**Water / Brine, SG**	1
Plastic Viscosity, cP	32	**Brine, % by volume**	63.01
Yield Point, lb/100 sq ft	11	**Average Specific Gravity of Solids**	4.06
10-sec Gel, lb/100 sq ft	4	**Weight Material, % by volume**	33.80
10-min Gel, lb/100 sq ft	12	**Weight Material, lb/bbl**	498
30-min Gel, lb/100 sq ft.	18	**Low Gravity Solids, % by volume**	3.20
API Filtrate, mL	3.4	**Low Gravity Solids, lb/bbl**	29
HP/HT Filtrate @ 300°F, mL	18.8	**Sand, % by volume**	0.1
pH	11.0	**Chlorides, mg/L**	1000
Mud Alkalinity (P_m), mL	1.4	**Hardness as Ca^{+2}, mg/L**	280
Filtrate Alkalinity (P_f), mL	0.6		
Filtrate Alkalinity (M_f), mL	2.8		

VITA

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